

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: _____ : Docket Number

REGIONAL TRANSMISSION ORGANIZATIONS (RTO): RM01-12-000

ELECTRICITY MARKET DESIGN AND STRUCTURE :

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Committee Meeting Room

Federal Energy Regulatory

Commission

888 First Street, NE

Washington, DC

Tuesday, February 5, 2002

The above-entitled matter came on for workshop, pursuant to notice, at 9:30 a.m., Kevin Kelly and Alice Fernandez, Moderators, presiding.

BEFORE COMMISSIONERS:

CHAIRMAN PAT WOOD, III

COMMISSIONER WILLIAM L. MASSEY

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

APPEARANCES:

ON BEHALF OF THE FEDERAL ENERGY REGULATORY COMMISSION:

ALICE FERNANDEZ, OMTR

KEVIN KELLY, OMTR

DICK O'NEILL, OMTR

DAVE MEAD, OMTR

UDI HELMAN, OMTR

ED MURRELL, OMTR

ANDREA WOLFMAN, OGC

ALISON SILVERSTEIN, Chairman's Office

ON BEHALF OF PANEL 1:

CRAIG BAKER

Senior Vice President of Regulation and Public
Policy, AEP Corp.

REEM FAHEY

Director, Market Policy, Edison Mission Energy

JIM CALDWELL

Policy Director, American Wind Energy
Association

APPEARANCES (Continued):

JOHN MEYER

Vice President of Asset Commercialization,

Reliant Energy

DANNY O'HEARN

Northwest Portfolio Manager, Powerex Corp.

RICKY BITTLE

Vice President, Planning, Rates & Dispatching,

Arkansas Electric Cooperative Corp.

MARK KLEINGINNA, Corporate Energy Director,

Ormet Corporation

RUBEN BROWN, E-Cubed Company, LLC

APPEARANCES (Continued):

ON BEHALF OF PANEL 2:

STEVEN T. NAUMANN

Transmission Services Vice President,

Commonwealth Edison

MICHAEL SCHNITZER

NorthBridge Group (Energy Consultant)

RICHARD DOYING

PG&E National Energy Group

ROY THILLY

President & CEO, Wisconsin Public Power, Inc.

RAY COXE

Senior Vice President of Transmission Marketing,

TransEnergie U.S. Ltd.

LAURA MANZ

Manager of Transmission Planning, PSE&G

STEVE WALTON

Consultant (RTO West)

-- continued --

APPEARANCES (Continued):

WAYMAN SMITH

Williams Energy Marketing and Trading

JOSEPH T. MARONE

Director of Power Purchasing, Occidental Energy

Ventures Corporation

PROCEEDINGS

MS. FERNANDEZ: Good morning, and welcome to our second series of conferences on standard market design. It's going to be second in a series, so that there will be other opportunities for conferences.

This week, we're going to talk about -- we have six panels over the next three days to talk about various aspects of standard market design and what should be included in a potential from the Commission.

Today we have energy markets and operating reserves in the morning, transmission rights and finance rights in the afternoon. Generation adequacy and transmission tariff transition are the topics for tomorrow's panels. And on Thursday, we're going to have market power mitigation and minimizing implementation cost.

In terms of some general logistics, we've asked all of the various panels to start off with, say, like an opening statement of no more than about three minutes to sort of give the basic position on the topics.

In the back of the room, there is a package that we've put out that gives the agenda and also some various questions that we have sent to the various panel members before, to give some idea as to the general types of topics that would be discussed in each of the panels.

We're probably going to break for lunch around 12:30, and we are going to try to work in a short break during the panel so people won't have to sit for three hours straight. The sessions are likely to end around 4:45, 5:00 each day.

One other topic that I'd just like to remind everyone is that RM01-12 is an open docket. If people have opening statements that they would like to file, they can be filed in that docket. If people hear things during the conference that they would like to comment on, they can also file them through that docket.

The purpose of this week's conference is to get additional views from all segments of the industry. I think we have very distinguished panels for each of them, representing various segments and viewpoints. In terms of the procedure, I'm going to largely turn it over to Kevin now.

Why don't we first introduce the people here at the table. I'm Alice Fernandez from OMTR.

COMMISSIONER WOOD: Pat Wood from the Commission.

MR. O'NEILL: Dick O'Neill, ditto.

MR. MEAD: Dave Mead, ditto.

MR. MURRELL: Ed Murrell with OMTR.

MS. WOLFMAN: Andrea Wolfman with the office of

general counsel.

MR. KELLY: And Kevin Kelly from OMTR.

MS. FERNANDEZ: Kevin Kelly is going to be the moderator of our first panel, energy markets and operating reserves, so I am going to turn it over to him.

MR. KELLY: Let me first thank the panel for joining us today. I will give a brief introduction to get us going, and then ask each panelist to make a short introduction about their views on the topics of the session.

The topic of the significance is energy markets and operating reserves. We'll focus our discussion on the challenges of standardizing design requirements for spot markets for energy.

Other panels later this afternoon and later this week will give special attention to markets for capacity such as the New England ICAP market, monitoring markets, and market power mitigation and transmission issues.

As you all know, we held a conference a couple of weeks ago where we heard presentations from participants and organizers of some of the existing organized spot markets, PJM and New York ISO, New England ISO, the Midwest ISO, RTO West and ERCOT. That discussion centered around how those organized markets functioned and

where improvements were needed.

This morning's panel will allow us to get into some of the more important features of energy spot markets and do so in a little more detail, and also to hear from those who are customers or potential customers of organized spot markets.

The questions that we sent the panelists some time ago to think about for this session, in summary, are should the Commission adopt -- and many of you are getting used to this jargon now -- the bid-based security constrained market design with locational marginal cost design pricing.

We talked last time about operating physically such a market at the nodal level, but having trading hubs and zones to facilitate commerce. We also are asking the panelists what elements are needed in the market design to meet the special needs of hydro resources, intermittent resources, distributed generation and price responsive demand. We asked should the Commission standardize whether to have a day-ahead market or to require balanced schedules, and what standards should the Commission adopt regarding markets for ancillary services.

After the opening remarks, we're going to engage in a discussion that will go some 2-1/2 to three hours about this issue. We invite all to participate.

And if there's some time at the end, we may invite questions from the audience.

Let's get started. For those of you who have seen the panelists' notice list, you will be expecting to see Rich Cowart, but Rich called just a few hours ago to say his flight out of Vermont was canceled this morning. Unfortunately, he's going to miss our panel. I know two of our participants care a lot about this, and they've agreed to pick up the slack there.

So let me begin by asking Craig Baker from AEP to introduce himself and to state his position.

MR. BAKER: I thank you. I appreciate it. I think you already introduced me, Kevin. I'm Craig Baker from AEP, and I want to thank you for the opportunity to come and be a part of this very distinguished panel and have the opportunity to give some input.

AEP fully supports the initiative of creating some standard market designs for RTOs to achieve the ultimate goal of achieving robust markets.

I think one of the areas of disagreement is how robust the various markets are in various areas of the country, but standard market design is a helpful tool in giving RTOs what they need. We believe that the general building blocks, that have been proven for congestion management systems that have worked in areas like the

Northeast have benefits, such as having market clearing prices using LMP, having financial transmission rights, and even permitting unbalanced schedules, are things that are helpful in the development of these markets.

I think we need to make sure, though, that there is enough room in these standard market designs for differences in regionality and differences in the way the markets operate. So there needs to be standardization, but we need to temperate it with seeing how it fits in specific areas.

In general, I think the framework for standard market design should not be overly prescriptive. It should provide standards, but be less prescriptive more than more. It should lead to a design that has not a tremendous amount of RTO involvement in the universe of energy markets.

I think they need to have the markets they need to produce the short-term reliability and to be able to make sure and keep the lights on, but there are probably areas of the market that it would be better if the markets were contestable, that other parties could come in and offer to provide those same kind of market services in competition with the RTOs. I think we need to make sure we permit bilateral transactions on a going-forward basis.

That is clearly something that is dominant in

almost every area, but certainly when you look out at the tight pools, that is the market design that people have become very used to, and we really shouldn't get away from that, but we need to make room for evolution. Markets evolve. RTOs will evolve, and we really need to make sure we don't cast things in such a way that they can't be changed.

PJM is a great example of that. They talk often of how much they've changed over the years as they've found out what the market participants are looking for. We need to keep that open for all markets as they evolve.

Thank you very much.

MS. FAHEY: Good morning. My name is Reem Fahey. I am the director of market policy for Edison Mission Energy. Thank you for inviting me.

I was very encouraged to see the Commission Staff chose energy markets as your opening panel. I believe hopefully that it's a sign of acknowledgment that the spot market lies at the core of the market design, and you have to absolutely start with this part. And the consequences of getting this part wrong will be very grave.

I believe that the RTO has to absolutely run the spot market. It has to be integrated energy and

transmission, and hopefully you will not allow any other entity to run the spot market. It has to be the RTO, and I believe it should be a bid-based security-constrained dispatch. I believe that the RTO should clear congestion in the real-time and balance the system simultaneously.

As far as the day-ahead markets, I also believe that the RTO has to run a centralized day-ahead market, and I believe that for two reasons. The first one is I'm a true believer that the transmission rights have to be completely financial in nature, and like any other financial instrument, it has to be settled at a certain point in time, and I believe that point in time is the day-ahead market.

It allows the market participants to give meaningful schedules to the RTO because of the two settlement system. And because of deviations from the day-ahead schedule, the market participants would be at risk of these deviations in the real-time market. So this really, in my opinion, also dictates that the RTO has to run an energy market, because energy and transmission are intertwined, and you cannot separate them, at least in the day-ahead market and the spot market.

And I also believe that it is critical that the RTO run that for the sake of reliability. On the day-ahead basis, the RTO will have a very good

understanding of what the load forecast is for the next day, the weather forecast, will have a good guess of generation availability, transmission availability, and so forth.

And it's important that the RTO take a snapshot in time and decide am I going to be reliable for the next day? Do I have adequate capacity? And we should allow the RTO sort of the final decisionmaking to say if the market participants did not commit enough resources to allow the RTO to do that in order to ensure reliability.

As far as balanced schedules are concerned, first, I believe it's critical that the RTO assure that there is adequate capacity in the market, and that's done obviously on a forward market at least a year in advance. But having that, given that that's the assumption, I believe that having a balanced schedule is absolutely not necessary, it's very restrictive and will become an obstacle for intermittent resources to fully participate in the market.

As far as trading hubs are concerned, I think it's very critical that the RTO work with the market participants to define the trading hubs, so that we can foster bilateral trading markets. The RTO should allow market participants to source the transactions from the hub and sink the transactions at the hub, allow them to

buy financial rights from the generation portfolio to the hub, from hub to hub, and from hub to load.

And finally, regarding operating reserve markets, ultimately, I believe that the RTO should run a bid-based reserve market that's fully integrated within the LMP algorithm. However, I would discourage the Commission to mandate that on day 1.

These markets are very, very complex, and they're the smaller part of the market, they're between 5 to 10 percent. And I believe that the Commission should focus on getting spot and day-ahead and other parts of the market done on day 1, and defer reserved markets for at least a year.

Thank you.

MR. CALDWELL: I'm Jim Caldwell, and I'm policy director for the American Wind Energy Association. As a representative of intermittent resources, I'd like to make an expansive definition of that so that I can get some friends on this panel.

Traditionally, we've thought of intermittent resources as the renewable resources, wind, solar, and run-of-the-wind hydro. But for purposes of this panel, for purposes of markets, it also includes all of those resources whose net output is affected by the load in which it resides or in which it serves. In other words,

also resources that have other businesses, other than the generation of electricity, who are participating in the market.

So cogeneration, many forms of distributed generation, and demand-response share a lot of the needs that we have in real-time markets. Therefore, the treatment of these resources is critical, not only to these individual technologies and individual resources, but also to the overall market performance.

If we look at future predictions as to where this market is going, we could represent as much as a third of the resources in this country. And if we don't design a market that allows for these resources to make physical delivery of their product in real-time, the markets will be inefficient, costs will be higher, and reliability will be affected.

The second point I'd like to make is, what do we really need in the real-time markets? We need an efficient, mature, liquid, transparent, real-time spot market. We need penalty-free imbalance settlements in that market. We need flexible, near real-time scheduling, and we need efficient secondary markets and transmission rights, arbitrage between real-time, spot, and day-ahead forward markets.

And that list that I just gave, all of those

are things that people who are interested in efficient markets generally say. All of these are consistent with and are required for a least-cost delivery of electric services. So we don't need special consideration, but what we do need is, again, mature, efficient markets, and we don't have those today.

The lack of all of those characteristics in the systems that we see are systemic in the Order 888 pro forma tariff as it has come to have been practiced in probably 75 to 80 percent of the country. And the practice of the pro forma tariff raises system costs and adversely affects reliability.

The idea of balanced schedules and imbalance penalties are artifacts of a time when outside transactions represented a small fraction of the system operations. They're a disaster when all load is served under this paradigm.

If we try to make all transactions balance, each individual transaction then requires its own ancillary services, its own reserve margins, and therefore, the system then requires maybe -- at least when you look at the data from the systems that are doing two, three, four times as much ancillary services -- as much operating reserves in order to operate efficiently as a market that balances the system as opposed to the

individual transactions. And this raising of the reserve margins and the draining of ancillary services raises prices and adversely affects reliability.

We have no doubt that eventually we'll get there, that eventually the efficient markets will win and that we will be able to exist. Our fear is that tomorrow is a long time and that we note that in spite of the best efforts of this Commission, that 75 to 80 percent of the country does not and is not -- has no prospect in the short-term of achieving the kinds of efficient market designs that we see here.

So we feel it's going to be important for interim relief for intermittent resources. Interim relief on the order of what the California ISO filed last week in its amendment 42 where what the California ISO said, in return for scheduling that is guaranteed to be unbiased, that is that it is not -- that there is no gaming of the schedules, that statistically there is just as much chance for being over as being under -- that we would be allowed to have monthly netting, and over a month period of time, rather than settling every 10 minutes, we can ensure that we can, again, indeed, follow those schedules. And that kind of interim relief is the sort of thing that we need, pending the efficient markets that we all are looking for.

Thank you.

MR. O'HEARN: Good morning. My name is Dan O'Hearn, portfolio manager at Powerex Corp. I want to take my few minutes here to give a background on what Powerex does, to help us get some understanding on where my viewpoints today will come from.

You probably see us as both a marketer and a generator. We are the marketing arm of BC Hydro, and through that, we have access to 10,000 megawatts of generation, which is predominantly hydro-based, via treaties between Canada and the U.S. We have another thousand megawatts of hydro generation in the Pacific Northwest, and we physically move power throughout the west, predominantly in WCC and to a lesser degree in MAP. So you would probably see us, like I said, as a marketer and both a generator.

We're based in the west. We have a little bit of activity in the east, but primarily we're western-based. We are knowledgeable about hydro. We have large storage reservoirs as well as run of the river. And lastly I can provide a bit of a Canadian aspect on some of these issues. I look forward to the panel discussion to bring out some of my viewpoints.

Thank you.

MR. MEYER: I'm John Meyer with Reliant Energy. To give you a little background, I've spent about 30-plus

years in the industry, all sides of it, both utility and unregulated, and have worked on designing markets, probably most notably in the ERCOT or Texas systems, but I've been in others, too.

I want to start out with a couple of introductory remarks that deal with the markets, and they're very important. The first one is that we can't underestimate the importance of the governance that we design into an RTO system. This is overlooked a lot of times until the end, and the problem with this is you don't get buy-in by everybody up front, and when you don't get that, things tend not to work as well.

The RTO's structure needs a truly independent leadership or board, with meaningful stakeholder input through a balanced sector stakeholder group, committee members. PJM is currently configured as a real good example of this. There are others, but I think they're probably one of the best.

The second comment in general I'd like to make about markets is these markets are highly integrated, and the rules associated with them and incentives are highly integrated. So I've seen pieces in a lot of reports that say we want to take the best practice of this and the best practice of that. When you pull those best practices out of varying places, just be sure you still integrate them,

because if you don't, you will create incentives you can't dream of for the participants.

As far as the markets themselves, turning back to the attention of today's topic a little more, we believe that a day-ahead market managed by the RTO is a requirement. The energy market should be a financial-only market. We believe there should be ancillary services, and unlike some others, we believe they should go in first, particularly spinning reserves and regulation markets. We believe scheduling should be imbalanced or imbalanced schedules should be allowed. It doesn't mean you can't balance them, but you shouldn't have to balance them in that day-ahead market.

As far as other ancillary service markets, I think it depends a lot on the unit commitment approach. I think the other week, we had a spokesman from PJM that made this point. The way they do unit commitment, they don't need longer-term operating reserves, nonspinning and replacement.

And how you design that, I think, is dependent on whether you're going to need those markets. Real-time markets -- this has taken me a long time to get there -- are possible, but as I look at a real-time energy design for the whole U.S., I believe it should be a nodal, bid-based security-constrained flow-type model with

marginal-type pricing.

I didn't use the word "marginal cost pricing" because I don't believe it's based on cost. I believe it's bid-based, and I think what you mean is you're selecting the lowest bid as the cost, marginal cost in that model.

As far as financial rights with that model, I believe that there should be two forms of financial rights, and they should only be financial. One is between the exact nodes and one is between paths or hubs, hub to hub where hubs can be created. These should -- once these financial rights are configured, they should be 100 percent auctioned.

Any existing or arguable contractible rights that existed should be covered by revenues from those auctions, not by allocating the rights themselves. Otherwise, you disadvantage different players in the market. And if it's been done right, you should be financially whole.

And the problems we run into there, as we heard the other week, was many paths tend to be oversubscribed. So if you just allocate -- when you sell the rights to those, you're only going to sell the rights that can actually be physically done, and when you allocate that money, you may not cover all the rights of a previous

party had.

One other thing there that we tended to disagree a little bit with some of the presenters the other week is, I think, transmission rights should be an option. I don't believe they should be an obligation. This is a little complicating when you do this, because essentially you have to make them directional only, which isn't too bad for hub to hub. It's a little tougher on the nodal, understanding the financial ramifications of doing that.

Quickly, on just a few other features, and then I will turn this over. I think all schedules need to go through the RTO, and as someone said a little earlier in the panel, self-scheduling should be allowed or bilateral transactions should be preserved. In many of these systems, like PJM, others, they are, obviously.

Commitment to bid, I think some of the questions that Kevin had asked us, which we wanted to address, was how do we get generators committed to bid into markets. Even though we're not supposed to talk about it, one way is to design the adequacy or the longer-term market right. So when you have a generator that commits and receives the capacity payment, he has a commitment to bid into the market. All the time that he is available.

I think the biggest thing that we need to address -- and there's a conference next week obviously -- is demand must be allowed to bid into all capacity and energy markets, as long as it has proper metering in place to recognize its response. And I see a lot of -- there's numerous issues associated with that that will have to be addressed, like who has the rights for the interruptibility, the demand or actually the supplier.

And I guess lastly, the last comment I'd like to make, we have to figure out a better way to manage generators and load pockets. This happens a lot in the nodal where they use offered caps, but the problem with an offered cap is you never really get out of that situation.

I think a preferable way is R&M contracts, though they need to be priced at new entry price, and that's so new entry will build and the situation will either go away or the price will reflect the value and you'll build new transmission into that load pocket. And I think with that, I will stop and address all the other remarks as we go through the rest of the morning.

Thank you.

MR. BITTLE: Good morning. I'm Ricky Bittle with Arkansas Electric Co-op.

I think there are several things that I want to address. One of them is the market power issue, because I

don't think that you can design the market unless you keep that in mind.

Basically, I think that the generation concentration issues that we've got now are going to be there. They're going to be there for some time, and they have to be dealt with. Just going into an RTO does not eliminate the concentration issue.

There are load pockets that are out there. John just mentioned those, and one of them -- it's not something that going to go away. As a matter of fact, I think it will probably get worse and the number of load pockets will grow basically because transmission is not being built.

Loads are growing and more generation is coming on-line, and so the load pockets will increase, and it's those areas that are at most risk for market power issues.

The other thing is that wholesale load really is going to have limited elasticity, and until there is something done at the states, basically we will be talking about just wholesale loads, and the wholesale loads are limited in what they can do with the individual loads by state law, in most cases.

The other thing that's there is I do support the use of LMP. However, it is one of those things that even though it provides price transparency there, are a

couple of things that have to be kept in mind.

All of the historical trade-offs that have been made between generation and transmission are now going to be priced in very local areas, and this is going to be major. It's not something that can be ignored. It's got to be taken into account when you start talking about conversion of rights for grandfathered rates.

The other thing that's there is local flow causes congestion. So in effect, you have local loads that are going to be paying for someone else's use of the transmission. Now, in the past, this has all been socialized, and it's been basically hidden, but now it's going to be priced in very localized areas. So it's something that just has to be addressed as we move forward.

Of course, something near and dear to my heart is this process of standardization of seams. The more standard, the less problem a seam is, but I will most likely be living on a seam in an extended period of time, have for a long time. And so it is one of those things that I think the more standard the markets are, the better, and so it will reduce a lot of problems for entities like AECC that are going to be serving in two different load control areas.

The other thing that's there is that

reliability, as we talk about it, while it's got both market implication and deliverability implication, it is one of those things that is a shared resource. I think it's really a community service, and basically as an entity, the whole interconnection contributes to reliability. And so it's something that has to be taken into account.

If everyone had to provide their own level of reliability, the cost would be much greater than it is now. I think the market design has to take into account the idea of reliability and deliverability, which LMP does, and if you settle at the spot price, then you don't have quite the same problem with the energy limited resources, and AECC does have some run of the river hydro, and so we are interested in that.

And as long as it's being settled at the spot price, we think that that will take care of that. It's either there or it's not, and if it is, you settle. If it's not, you don't. If there are penalties involved, that really raises some issues that should be taken care of by just settling at the spot price.

The other thing that I think is there is you can't have markets where there is only a single-sided response. If the generators are the only ones that can provide it but there's no way the load can react to it,

even in the long-term, then I think there's a problem.

Just as an example, I think regulation is one of those -- regulation really is an aggregation of the change of all loads, not just specific loads, and so even if a single load does something to change their need for regulation, it may make the problem worse for the whole system. Its change may have been going the opposite direction of others.

So all of those things have to be worked together. They have to be examined, and where there is not the ability to actually effect a change from the load's perspective, then I think, in those cases, those items really need to be procured by the RTO and socialized over a period of time.

Thank you.

MR. KLEINGINNA: Good morning. I'm Mark Kleinginna with Ormet Corporation. I just have three things to really talk about. Some of them may be rather controversial and not necessarily covered in what the questions are, but I think they pertain to energy markets.

The first thing is, I want to echo what everyone has said with respect to clearly defined independence of transmission and generation. I think that is absolutely, absolutely key, and I think it goes very far to place transmission in the hands of those who value

it the most, to steal from another extremely important order in the energy markets.

To read the question, "should the Commission adopt the bid-based security constrained market design with locational marginal cost pricing, operated physically at the nodal level, but with trading hubs and zones allowing generator and aggregation for commercial purposes?" And had to take a couple of breaths.

My initial reaction to that was I got very nervous because it took me back to 1956 and the Phillips decision, because what really concerns me here is that we get too prescriptive, as Craig Baker said, and I absolutely want to ensure for the end user that I work for, that bilateral transactions can take place, and I absolutely want to ensure that real, genuine trading hubs can be set up that are dictated not by regulatory fiat, but dictated by this is where energy trades and it makes sense for it to trade here, and this is where energy can trade fairly and it makes sense for it to trade here, and we've got genuine separation between transmission and generation because there are market concentration issues, and there are tying arrangement issues here that go completely back through the history of how the system developed.

So I just want to be sure that we do have

transmission in the hands of those who value it the most, and those who value it the most are guys like me. I want to have firm transmission, and I want to be able to get firm transmission of my load.

The second thing, which is maybe somewhat controversial and not really covered by the agenda, but really, it doesn't get a whole lot of notice when we talk about standardization, is losses. There's a joke about getting a loss on losses and losses get lost. We absolutely need to make sure that losses are dealt with in a standardized way across the entire interconnect so that there aren't -- there aren't specific incentives to operate the system suboptimally.

One of the pancakes -- we talk about eliminating pancakes in rates. We haven't eliminated pancakes in losses, and the losses are stacked this high (indicating) in terms of pancakes. So we absolutely need to make sure that we've got a methodology that works across RTOs. We need to make sure we have fairness within the RTOs in terms of how losses are dealt with.

A guy like me stands out, and I get inflicted with a loss payment. There may be others who aren't, and there may be certain generation which is favored as a result of inconsistency in treatment of losses within RTOs.

And finally, the topic which is near and dear to my heart and I will certainly be willing to talk about further -- and I'll quote from this piece that came out, straw man discussion paper. "State and federal policies to promote price-responsive demand will help customers reveal their own true willingness to produce energy which may be the most potent market power mitigation measure."

We agree with that wholeheartedly and have received this price signal. And we have assessed our willingness to purchase energy, and in fact, have decided not to on certain occasions as a result of these price signals. We also feel that there are end users, that are even better equipped, that are meant to provide these types of services to the market and feel that we would absolutely want to participate in a reserves market.

That is, we would absolutely want to participate in a spinning and nonspinning reserves market and feel, to the extent that we can mitigate costs there for ourselves, we would be happy to sign up and let the RTO know what it is we can do, and feel that bilateral transactions are extremely important for that, extremely important for that.

With that, I will close.

MR. BROWN: Thank you. I'm Ruben Brown for the E-Cubed Company, LLC, in New York City. I'm going to

speak to principles for ISO, RTO demand response, resource markets, DRRs as it's beginning to be called in the parlance.

I will define it quickly. I will indicate five principles for use in developing the programs, and I will summarize five or six DRR markets by specific reference.

The DRR includes all load with the capability of reducing electric usage, as well as on-site generation, including combined heat and power with facilities that can interact with the wholesale market institutions. DRR markets work by allowing customers or aggregators acting on their behalf to sell load curtailment into the market, much the same way generators offer to sell power.

The E-Cubed Company, having participated in the development of the ISO and RTO institutions in the Northeast over the last decade, is going to focus in these comments on practical realities. We think there is substantial evidence that DRR markets are working, that they need certainty and encouragement to attract investment.

DRR markets should be designed to encourage entry, eliminate barriers to entry, and be included at the outset in RTO development. To that end, we participated in the northeast RTO mediation, and in RTO we provided comments to the same effect. DRR should be allowed

participation in energy and ancillary service markets in competition with generators, as we've heard. And market mechanisms must be established to recognize the value of DRR, including, perhaps, a dozen values that we've identified, energy value, replacement reserves value, reliability dispatch value, locational value, planning value, capacity value, alternative to transmission expansion, which should be very important in the context of the infrastructure regional meetings in Seattle and New York in the last couple of months and the comments that the Commissioner and others engaged in on Thursday in New York regarding transmission relief and northeast demand response should be very much a part of that discussion and debate, congestion relief value, enhanced competition reducing the potential for market power and need for market mitigation, decrease system losses especially during peak loading periods by reducing line loading, decreased and more dispured emissions. At a minimum, payment for DRR should include a market clearing price, curtailment of initiation cost and competition for other market value attributable to DRR.

Our written text will be available to the Staff and is in the back of the room -- or is available right now -- includes specifically six markets that are ripe for inclusion, and that includes energy demand response

resources markets that's bid in a day-ahead market, settled day-ahead, bid in hour-ahead, settled in real-time, price-taking feature to make it easy and simple to enter. It's already a modified energy market proposed in ISO and PJM.

These are all things that are in existence or in the process in the Northeast, and to a certain extent in the Cal ISO and developing an ERCOT.

Ancillary service markets, 10-minute spin, 10-minute nonspin, 10-minute regulation voltage support, day-ahead bid-based selection of DRR. Highest accepted bid establishes a clearing price, participants counted on by the ISO RTO to perform possibly subject to penalties for nonperformance. Replacement reserve providers cannot simultaneously provide 10- or 30-minute operating reserves, for example, emergency demand response resources voluntarily. I won't detail that. And obviously, capacity markets as well on the bilateral and on the bid-based; in some instances, a green market might be available.

I apologize for reading, but there's a lot of detail here and a lot of experience and evidence that we can build on. I think it's time to move past the rhetoric of we need a demand response, and we can now go to particulars. These will also be addressed next week in

the conference you have organized with DOE.

Thank you.

MR. KELLY: Thank you all. Let me ask the first question. I want to tell you what I think I heard from the panel, and if anybody thinks I got it wrong, please tell me. I heard, from a fairly diverse group of panelists, general support with cautions for a bid-based security-constraint spot market to be required across the country, based on nodal LMP, with day-ahead market, unbalanced schedules permitted, and no balanced scheduling requirement.

Now, the cautions I've heard, I couldn't quite tell if they were cautions that said go ahead and standardize that, but do it carefully, or don't standardize it, we're not ready. I'm pretty sure Mr. Baker I heard to say go ahead and do it, but don't be overly prescriptive, but with Mr. Bittle, I was wondering if his concerns about generation concentration or Mr. Meyer's words about load pockets or Mr. Kleinginna's reference to the overly prescriptive Phillips description, like the nature of this, rose to the level of saying don't do it yet, don't standardize across the country, as opposed to saying look, go ahead and do it, but do it with caution.

Maybe I could call on Messrs. Meyer, Bittle,

and Kleinginna to elaborate, and if any of the others feel I've mischaracterized those views, please chime in. Otherwise, just those three.

MR. MEYER: I think I would be in favor of standardizing along the lines you've described. I think my word of caution dealt with make sure you have an adequate solution -- and maybe Ricky and I were saying the same thing -- adequate solution to deal with load pockets are really to bid transmission where required. I think one of the biggest fallacies I've seen in the RTO design is not a lot of new transmission gets built because there's various interests to keep things like they are.

I think that's a requirement. The idea is not to perpetuate a load pocket. It's to figure out a standard way not only to limit the market power there, if it exists, but also to eventually elicit it where it's just a part of the overall market again.

And I think the second part is what we've got to work on a lot harder, but I think the standardization of the nodal system, the day-ahead market with no restriction on balanced schedules, you can imbalance them or balance them, is a good idea to move forward on that basis.

MR. BITTLE: I think that where I was going, as much as anything, it really runs to the allowing of the

bidding rather than cost-based. You can implement the LMP either as a cost-based or as bid-based, but if you've got high concentrations of generation, it just doesn't make sense to allow it to be bid-based to me, in that you are really turning that over to someone that can control the market. If you look at the load pockets, then, generation or transmission could serve to mitigate whatever the problem is there, probably transmission in the long run.

The problem with LMP is it provides the information as to where something ought to be done, but really does not provide the incentive to get it done, in that as soon as you do something, you've changed the LMP pricing structure and you no longer have what you had before.

And so the pricing structure has got to be built in to the way transmission -- or the rates for transmission allow for transmission revenue recovery, and that's where the incentive for building transmission has got to be placed, which relies, then, on a good planning process.

And so there are several things that have got to fall into place in order to protect the people that will be in those load pockets, but as far as going ahead and implementing it, it probably could be done, but the prices that those people are paying have to be -- you have

to pay particular attention to the amount of money that they are being charged.

MR. KELLY: Just a quick follow-up on that one point, you said it should be cost-based and not bid-based. Earlier, I think it was Mr. Meyer said it ought to be based upon the cost of a new unit rather than a historical unit. Any comment on that?

MR. BITTLE: I think there you've got to be careful. If you charge them too much, you've got a problem. I think one thing, you know, you can learn a lot from some of the lessons we've seen over a period of time, and there two of them you find out. Too high a price or no electricity, either one, make a market that is not going to be accepted by the people of the United States.

MR. KELLY: Mr. Kleinginna?

MR. KLEINGINNA: I think that LMP -- and I understand -- I don't sit in a load pocket, but there are a lot of folks who are end users who do sit in load pockets, and I certainly believe that LMP provides a pricing that let us you know where the problem is.

And I want to echo what John Meyer said, and that is what do you do once you have that pricing. And I think that it is important that we do take action or provide incentives for folks to take action to solve the problem once it exists.

And I don't believe -- I know that I don't necessarily have a problem with LMP being used to provide a price signal. That's fine, at a nodal level. I don't really have a problem with that. The concern that I have is that we ensure first, before we prescribe an LMP, that we have provided for independence between generation and transmission.

And that, to me, the ultimate -- the ultimate tying arrangement here to branch off an economic theory, transmission's the monopoly, and absolutely we have to make sure that the tying arrangement can't take place between generation and transmission to make LMPs look particularly ugly for guys like me, and that's truly, truly the concern.

With respect to that, we can -- you know, we can make sure that financial transmission rights are placed in the hands of those who value it the most, and quite frankly, as a practical matter, I'm a firm believer that we can do that, and if we do that first, then we can go to LMP, and that's fine, but I don't want to prescribe a price for a place, but not have the ability to hedge personally that transmission cost to get the power to my load.

MR. KELLY: So would it be fair to say that you would not recommend yet standardizing bid-based

security-constrained LMP, or to solve the transmission problem at the same time as we go there and do that --

MR. KLEINGINNA: Solve the independence problem now, and you can prescribe LMP at the same time. That is certainly fine. Prescribing LMP first and not solve the independence problem, and you've got the same mess you've got now, or potentially worse.

MR. KELLY: Thank you. I want to give other people a chance to ask questions, but is there anybody who wants to object to my general characterization? Quite a few. Mr. Baker?

MR. BAKER: Kevin, I think to a great degree what you said we're supportive of. A couple of things, though, that I'd like to clarify, the day-ahead market, I'm not supportive that that needs to be run by the RTO. I think that can be run by someone else if the market participants so desire, and it will stand on its own as a market that either is of interest to market participants and they're willing to pay for it or it doesn't.

I think LMP is a very good starting point. It's kind of like our governments. The best point we've found to date, and it may turn out that 300 years from now it will still be the best, but I think we have to leave it open for the potential of other approaches that are as good or better. And then lastly, the nodal aspect makes

sense, to me, but we clearly need to set the number of nodes around what it takes to manage congestion for the RTO so it has the tools it needs to serve reliability and keep the lights on.

MR. KELLY: Ms. Fahey?

MS. FAHEY: Just very briefly regarding standardizing LMP. I guess maybe the question is if people are opposed to LMP as the efficient tool of creating the spot market, what is the other alternative? And we haven't heard another better alternative. Nobody's saying that, you know, LMP is perfect, and it's not going to be painful. It's going to be painful for load pockets. We all acknowledge that.

But LMP works because, first, it acknowledges the physics of the system. So we're not doing something just to make things easy, but it's against how electricity works, and the other one is if we look back to prior to deregulation and vertically integrated model, that's exactly what the system operator did.

It's absolutely that, but now instead of dispatching the units to keep the system secure based on cost, now we're doing it based on competitive bids from the generation. So I think if someone is telling you don't do LMP, then they have to come up with a better model.

MR. KELLY: Mr. O'Hearn, you wanted to say something, and I would like to open it to others to have a free discussion.

MR. O'HEARN: We discussed cost-based bidding. I want to make it clear, for costs, for hydro, of course, it's opportunity costs. It's not just the marginal costs. I wanted to make that point.

As far as standardizing the markets, we feel that they don't necessarily need to be run by the RTO. A third party can do that, and there's some advantages with that, and that a third party can probably be quicker and more market-responsive to the needs of the markets.

With a bilateral market, we wouldn't want to have any market design that would be prohibitive to having a bilateral market. A bilateral market can respond very quickly, whether it's a new product or service that's needed, a new trading hub. Maybe power needs to be traded to a specific location that hadn't been there before, and with having a third party doing those markets, I feel that we get the quickest response on that.

That's it. Thank you.

MR. KELLY: Others?

MR. MEYER: I'm just going to reecho, I hope.

When we say cost-based bidding, I think we were referring only inside of load pockets where market concentration was

an issue and not in general the LMP. It's a bid-based system.

MR. BITTLE: I would have to say that's anywhere the concentration is excessive.

MR. O'NEILL: Let me just agree, but Craig, you know, as Reem was saying, we have experience in LMP and day-ahead markets are not perfect, but in California, when we got rid of the day-ahead market, California is now proposing to put one back in. In New England, they assured us they didn't need a day-ahead market, and now they're proposing to put one back in. PJM and New York seem to be happy with their day-ahead market.

So it seems to me in every case when we've tried to do without it, we've come back and decided we needed it. What makes you think we shouldn't do it now?

MR. BAKER: What worries me is the prescriptive nature. My understanding is that the RTO will have enough information to forecast prices without a day-ahead market.

MR. O'NEILL: We're not worried about forecasting prices. We're concerned with making sure reserves are where they need to be and there's enough generation commitment to satisfy reliability. Every time we talk to the operators, the day-ahead market is what they say they need as opposed to a real-time market, because they are -- they don't think they can manage the

reliability of the system with simply a real-time market.

And if they don't have a day-ahead market, they take administrative action to schedule reserves into the market, which doesn't make it a market at all.

MR. BAKER: If you're looking for operating reserves and spinning reserves and regulations, I think that can be entered into contractually by the RTO.

MR. O'NEILL: Do you have something written up on that? We've been through these discussions, and we need to have a more concrete model to look at. If we're going to go into a process where we start to standardize, you know, we need to have something to look at as opposed to sort of saying we can do this or we can do that. Do you have a --

MR. BAKER: I don't have anything, but let me go back to the shop and see if we can put something together.

MR. O'NEILL: My final question is, could you be specific on where you think the bilateral market is inhibited in this standard market design? Because in designing standard market design, we really do try to make sure that we're not preferencing the bilateral market, it can play as it sees fit, and if there are things that are biasing that market, we need to understand them, because I think most of us believe that you need a vibrant off-RTO

market, if you will, in order to make these markets work.

MR. BITTLE: May I ask you a question? Are you assuming that the day-ahead market is financial or physical?

MR. O'NEILL: It turns out to be both. In the existing New York and PJM, they run the day-ahead market, it turns out, the first pass is financial, and then they make a second pass if the operators think that the physical market isn't going to be reliable. So it essentially is both.

All of these markets have to be financial by nature. If you make a commitment, you have to make a commitment, you know, and you're financially bound by it. But in addition, they use this as a tool to make sure that they're comfortable going into the day-ahead operations with the way the system's configured.

MS. FAHEY: I just want to emphasize something that you said, which I hope that the Commission would really focus on, is ask the system operator. I mean, the system operator needs to operate the system. If their experience so far indicates that they need a day-ahead market -- and I used to be a system operator. And part of what we did, especially in the summer periods, we absolutely had to have a very clear idea of what's going to be going on the next day, because, you know, if we're

going to be planning on interrupting load, if we're going to be planning on emergency operations, we had to plan that the day ahead. You cannot leave that to the spot market.

And I'm not saying to interfere in bilateral trading. I'm not saying that. If somebody wants to self-schedule, let them. They're just telling you I'm going to generate 500 megawatts, and the system dispatcher says great, I can accommodate that, that meets my reliability and adequacy criteria for the next day.

I truly think it's a big mistake to divorce transmission and energy in the day-ahead market, and obviously more specifically in the spot, but I think it's absolutely critical that you run a day-ahead market -- forget, you know, the financial part -- for reliability's sake. And again, I just reinforce, you have to speak to the operators. That's typically what they do.

MR. MEYER: I'd have to agreed with Reem there. Having run the control center for HL&P, which was one of the larger utilities in Texas at the time, the day-ahead or market looking the day ahead, whichever way you want to call it, you've got to have the unit commitment.

This is one of the problems where we've seen kind of disaster in California with no way -- whether the financial provides really a lot to price and an indication

of where you're going, and then as Dick has described, then the operator looks at unit commitment further to see if it's realizable or he needs more units in a commitment.

But that has to be done the day ahead. There has to be a mechanism in the day ahead to handle that process. Otherwise, the operator's at a very big disadvantage as he approaches real-time. I think we've demonstrated that at various places.

MR. BITTLE: But I assume what you're saying is that any deviations that occur in real-time are settled at spot.

MR. MEYER: Yes.

MR. O'NEILL: But the hope is -- and I think it's borne out by experience -- that deviations are not serious enough to threaten reliability, and interestingly enough, you don't need penalties to do that. It seems to work itself out if you get the market design right.

MR. CALDWELL: I think we tend to focus too much on the technical details. We're all sort of techies and we like to talk about those things and kind of forget what problems we're trying to solve and what performance measures we ought to be looking at.

In echoing something that Reem said, I think if you look at what problems we are trying to solve, we're trying to solve the dispatch problem, we're trying to

solve the commitment problem and ultimately trying to solve an investment problem as to what kinds of things and how much are we going to build where.

And those are the problems that we have to solve more efficiently than the old system. Otherwise, we're not going to win.

And when you look at the performance measures, I think you can say that in order to get there, in order to solve those problems, that we have to have a liquid, transparent spot market. If we don't, that market design is ineffective. We have to have efficient sharing of reserves. We can't balance each individual load, each individual transaction. We have to share those reserves.

If we don't share reserves, we're going to require too much reserve margin, and the system is going to be too costly. And there needs to be fast, accurate, transparent settlements for cash in these markets. If we don't have those performance measures, it doesn't work, and I don't know of any other market design that has performed on those measures that we're looking at, other than whatever the phrase is, let's call it PJM for short here.

MR. O'NEILL: It's standard market design.

MR. CALDWELL: Standard market design. But I think, going forward, what we really need to do is focus

on what problems we're solving and whether the market that exists is solving those problems. And until we come up with those metrics and actually look at those and measure our performance on the basis of that, then we're not going to get anywhere. We can talk about theory for a long time, but we have to measure results.

MR. KELLY: Mr. Baker, I just wanted to make sure you had an adequate opportunity to get your views out. We welcome the paper, but are there some things that you'd like to say here now about the day-ahead market that you didn't get a chance to say yet?

MR. BAKER: I think, based on what Dick said, I think coming through with something that may be a little more descriptive on paper would be a little more helpful. As I say, I'm not unsupportive of the day-ahead market. If it's needed, people will install it, it can be run by a third party.

The question is, do you need it to be run by the RTO in order to do that. One of the clear concerns I have -- and I don't disagree that a system operator needs all the signals it can get in order to manage its system, but one thing we need to make sure of is that the system operator, as a result of these signals, is efficient in what it chooses to do and isn't overly conservative, because it may not have any skin in the game. It may buy

significant amounts of capacity just on a purely conservative nature, and that cost gets socialized. That is something that may be avoided if we don't have that market directly tied to the RTO.

MR. KELLY: I think Dave Mead had a question.

MR. MEAD: Let me follow up on this general line of question. I think both Mr. Baker and Mr. O'Hearn were suggesting that a day-ahead market might be a useful thing but perhaps the RTO doesn't need to operate it, perhaps a third party could do so. I presume if a third party does it, the implication is that all schedules that go to the RTO day-ahead must be balanced, and if so, it's not clear to me how we determine whether market participants prefer the third-party entity running the day-ahead market because market participants are precluded from submitting unbalanced bids -- or unbalanced schedules into the RTO.

Do I have something wrong there?

MR. BAKER: I don't think I indicated that you couldn't have an unbalanced schedule to the RTO. I believe you can, and the information that comes out of the day-ahead market from the third party would flow to the RTO, along with any schedules that anyone puts in. I didn't make it exclusive.

MS. FERNANDEZ: I guess I'm a little confused.

If you have a third party running the day-ahead market, it seems like there's sort of two models, and I'm not sure which one we're talking about. One would be, I guess, almost in effect that the third party is acting sort of like a subcontractor and that there's a separate market, people can go in with unbalanced schedules, can buy the power that way, and at the end of the day, the third party is responsible for giving the schedule to the RTO operator.

MR. BAKER: Okay. The party I would probably leave out is the subcontractor role. It would be -- it would be a market that was run by an independent party, because they believed that they could make money at it, because parties wanted to have the ability to bid in day-ahead and guarantee a position, and that there would be counterparties who had desires on the other side and would bid in appropriately.

Following that, I agree that at the end of the day, that information would go to the RTO as schedules from whatever the outcome of that market clearing was.

MS. FERNANDEZ: One reason why I said subcontractors, the way it was being discussed it sounded like there might be one entity doing it. Are you assuming there would be multiple entities?

MR. BAKER: I think there could be multiple

entities, yes.

MS. FERNANDEZ: Would each be coming up with, in effect, arranging bilateral transactions on the day-ahead market?

MR. BAKER: Yes.

MR. O'HEARN: And in aggregate submitting a balanced schedule to the RTO.

MR. O'NEILL: Balanced in what way? I can submit a whole bunch of balanced schedules, and the end result is that the combination of the balanced schedules is unbalanced. So I mean, who resolves those issues?

MR. O'HEARN: I personally never thought of it as being multiple third parties. I envisioned there being one third party.

MR. O'NEILL: So everybody would have to go through that third party?

MR. O'HEARN: Or to do bilateral transactions.

MR. O'NEILL: Who is responsible for making sure all of these transactions are simultaneously feasible, or do we just do what AEP does and call it the OR?

MS. FERNANDEZ: It seems like if there's one party doing it, that entity can determine that simultaneously, all the transactions are simultaneously feasible. If there are multiple entities, I'm trying to

figure out how to basically do the reconciliation.

MR. O'HEARN: I've never really envisioned how it would work with multiple parties.

MS. FAHEY: Plus, I think if you allow a third party to do that, then we're going to end up stuck with multiple iterations. So this third party, obviously, is not the RTO and has absolutely no understanding of this simultaneous feasibility of all the schedules. So they're going to correct the schedules, then submit it to the RTO. Then the RTO is going to optimize and say I can't accept schedule A and C and D, and so forth. I just believe that that operation is not necessary.

MS. FERNANDEZ: I know a number of the panel have made comments about demand response and intermittent resources. I was wondering if we might get into a discussion of sort of if there are items in the existing market designs in PJM, New York, New England, California that we could look at as a model if there are -- this is something that we have to create in terms of what should be built into a standard market design to sort of make better use of demand response?

MR. CALDWELL: Speaking as someone who tries to do business in most of the markets around the country, or certainly represents people who do, I can tell you there are very few markets that by their nature that we can

transact business and interstate commerce. One of those, at least in terms of the energy market, is PJM.

The key there is that it's a penalty-free settlement of the imbalances at the spot price, as people have said, and that spot market is transparent, and it is liquid enough that there are people there who will then take that liquid market and then write -- call them contracts or differences or call them whatever they are to convert that spot market position into a fixed price that then people that I represent can then finance.

And it's that intermediary who is there to do that, and he is not there if the market is not transparent and is not liquid. He will not take a position in that market or will not accept the risk of taking a position in that market if it's not transparent, if it's not liquid. That's the situation that happened in California where the spot market bore no relationship whatsoever to reality, to what was going on in the grid at the time.

The most logical or the most common price in the California spot market, when things went to a head, was zero. You could get a zero price in the spot market, and at the same time that the ISO was calling a stage 2 emergency.

You could get the position where I was talking to a company, Chevron -- I will name it -- that decided

that whenever the ISO was going to -- when they saw the ISO call in an emergency, that they would do things, everything they could to increase the output from their cogeneration and do things expecting to be rewarded. 70 days later they got a bill for \$500,000 for imbalance charges for uninstructed deviations. And that brings up something that Reem talked about.

Every time that you have one of these iterations and transactions between the third party, that then you make the settlement, the financial settlement extremely complicated, because data has to be passed back and forth, different databases and so forth, and there's no way you could come up with a quick, clear transparent settlement. I mean, it would be like trying to say I'm going to buy stock, but I don't know what the price is or actually how many shares I bought for 60 or 70 days down the road.

And that simply will not work. And so I think we need to concentrate again on the performance measures. Is there a liquid transparent spot market? Does it settle quickly for cash? Do people believe in the transactions? Do people share reserves? And if they do, then I think the market will be efficient, and the only design that works, at least as far as we can tell on the energy side, happens to be PJM.

Now, I will say this about PJM, in that they don't do the capacity side for us well at all, New York does a very nice job on the capacity side. And sort of the best practices, if you will, between New York, New England, and PJM, we think, is a standard market design that can work for intermittent resources.

MS. FERNANDEZ: Let's just go down the line.

MR. MEYER: I was going to mention some of our experience in ERCOT on demand response. We tried to build as much demand response as we could in the model. We obviously were aided because it does have retail competition. So demand is free to do what they want to with their right to interrupt or right to add load. But they built into all the capacity markets. The only one we had trouble with that we're still working to understand is regulation.

However, we have very large industrials that have embedded generation or processes such that they can follow signals, and they, I think, will work that one out and allow them to be in regulation.

Spinning reserve, we have a slight advantage because frequency goes down as spinning reserve is required, so we can use high-set relays to trip load. That may be a little more troublesome in the east where frequency doesn't change for unit trips and other

manager-type conditions.

But there are ways, I think, to handle it. We allowed -- all those, basically, loads that wanted to bid in those capacity markets had to have the same telemetry as the generator, and basic metering. Those are limited to fairly large loads. However, I think that's probably appropriate in those markets.

In the balancing market, which is a much shorter-term market, all they had to have was an interval demand meter, which basically whatever -- we were on a 15-minute interval. So they had to be able to recognize and record their demand every 15 minutes. With that, they could bid into the market without the telemetry, and only in what we call balancing up or increments. We didn't quite figure out how to do the decrements.

The other issue of demand -- I know I'm going into a little detail -- but you have to allow the ability when they come off to stay off a little longer. You can't basically expect them to be back 15 minutes later. Some can and some can't. It depends upon the process or the load. Many are going to be down an hour or so. You have to recognize there are a few differences and get used to that and allow that built into the market.

MR. BAKER: I believe that we really do need to have the ability to allow demand-side bidding into

whatever, just as generators. I think the biggest issue that we're going to have to resolve -- and somebody mentioned it in their opening remarks -- is who actually has the contractual right to the capacity and energy that's being bid in.

In many areas where deregulation has become a customer choice, it's very easy to make that definition. Or if there are contracts that have been entered into by parties where, in the more current contracts, it's clearly defined. When you think of an older retail design where you set rates around a certain expectation of load factor, which was significantly less than 100 percent and that benefit resulted in lower rates for customers, how do you manage that question of who owns the right to the capacity or energy when it's not used?

An example that I can give is just a customer that we deal with who always has taken maintenance down -- taken maintenance on a Monday, and that has been built into the rate design. Now, when the price in the market hits a very competitive, good price, who has the right to that Monday energy? Is it the incumbent utility who provides the service the rest of the time, or is it the customer?

And it's a tension and something that needs to be worked out in developing that demand side, but once you

figure out who has the contractual right to it, then I think it's a very important feature.

MR. BROWN: Thank you. Obviously, we believe that the experience in all three of the northeastern ISOs, on different markets, offer best practices that are percolating to the top. The most evolved concept piece is actually a proposal in front of PJM at the present time, which is rolled out of the best practices experience of PJM, New York ISO, and ISO New England to a certain extent. Customers and aggregators are beginning to learn to interact with the institutions to achieve performance.

Now, performance was negligible this year. However, 600 megawatts of activity occurred in New York. If you include the active load management program at PJM, which is a historical program, 5 percent of PJM's load, in effect, did demand reduction activity this year. If you remove the active load management, it was negligible.

So we go back to the need for clear, standardized signals across ISOs and RTOs that provides full transparency, as others were requesting, to decisions that would stimulate all these markets. We think the experience is there. We think market participants are there, but the investment will not come out as long as the signals are ambiguous and confused.

MS. FERNANDEZ: When you're saying the signals

are ambiguous and confused, signals --

MR. BROWN: We have different signals in the three different ISOs, for example. Now, obviously, we've participated in designing them. We got some in some market stakeholder processes, and we got others in other processes, so that you have products that are available in one ISO -- for example, you've got two ISOs talking of forming an RTO.

They're now starting into a negotiating process. They do have different products in this area to deal with. They'll rationalize that to a certain extent in the stakeholder negotiations in the next three or four months.

But if laid on top of that, we had the opportunity to address a standard market design process here, things that might affect that RTO and other RTOs in the making, we wouldn't be having, in effect, design that was, well, inconsistent, for -- I'm talking about performers who want to perform in multiple markets, similar to the generators at an earlier stage. They would like to have a focus set of market signals they could work to, and I guess the demand responses industry and distributed resources wish the same.

MR. KLEINGINNA: I think that's exactly right. There does need to be some consistency and some

standardization across markets on this. You'll get folks in certain markets who will be very demand-responsive and folks in other markets who are completely demand-unresponsive, and that may not be the societal optimal solution.

I would once again say that, you know, we're in the Midwest. We don't have LMP there. There are -- and we've been as demand-responsive, we think, as virtually anybody. I think that LMP -- I would like to see the LMP price signal. That would be great. It's nice for me when I can log on to my computer and take a look at what the LMPs are and see what's going on, and I'm not that far from the LMP world, not that far from PJM, and can see what's happening over there, and it gives me an indication of what's going on in that market. It's not my market, but it's close to my market.

I would like to have an LMP at the tower delivery point in Hannibal, Ohio, you bet. That would be great. That would be fabulous. I'd love to see it. Am I ever going to transact on that price? No, not on a bet. I won't transact on that price, because I will have already done the deal. The deal will already have been done, and I will have accepted a premium for the ability to take my load, and that is -- and someone else may settle against LMP, but I'm certainly not going to do

that, because my particular economics don't just have to do with what's going on in the power market.

My particular economics have to do with what's going on in the metal market. I arbitrage power and metal all the time. And so I'm going to make that decision in March, maybe, of this year for two years from now to what I might be willing to sell that capacity for and what strike price I might be willing to do, and someone else is going to take the bet on the LMP side.

So it's important that we recognize that, and that market that I've just described, where I can sell rights for power and interruptibility has developed, and I've got folks who come to me and say Mark, you know, if you give us 50 megawatts, you know, four hours a day for July and August, I'm willing to give you a premium for it, and we'll give you a trigger price of X. And then they take the risk.

If you want to put LMP in that, that's great, because that's going to provide liquidity and potentially get more folks bidding for my, hopefully, valuable capacity or hopefully valuable -- not capacity, necessarily, but energy or rights to that energy. I think it is important that we do design this well but design it -- and you can design it with LMP, if you like, but design it in such a way that I'm not forced to take LMP,

that I can go out and make sure that these transactions can occur and we're not actually limiting what's going to happen here. That would be the only concern that I've got.

MR. KELLY: We promised the panelists a break around 11:00. Could we be back here in five minutes sharp and resume.

(Recess.)

MR. KELLY: Welcome back, everyone. Several of the FERC Staff indicated they wanted to ask some questions on the topics we've been covering. I'd like to, after that, save a decent amount of time for talking about the reserve markets and hopefully save a little time at the end to get questions from people in the audience to participate. I think Alison Silverstein had some questions.

MS. SILVERSTEIN: Good morning.

My first question goes to the matter of standardization, and some of you had said you're pro standardization, and lots of people said we want flexibility, standardization with flexibility. I'm not sure what that means, and I'd like to explore it a little bit.

We're going to explore this by just going down the row and asking the following question: How do you

standardize something in a way that maintains flexibility and solves these problems? We've danced around this in some prior discussion, but nothing particularly specific has been said.

And let me offer you a couple of questions to make this more specific, particularly for those of you who are flexibility fans. How do you standardize something without being overly prescriptive in a way that assures that a market works across seams? How do you prevent things like incompatible time specifications of 10-minute versus 15-minute intervals, or at what point you start your hour-ahead measurement? If you do not get as prescriptive as saying it starts at 10:00 and goes to 11:00 or bids must be in by 2:00 p.m., how do you avoid incompatible software or pancaking if you do not get very prescriptive? So perhaps we can gallop on down the row and talk about that a little bit.

MR. BAKER: What you have to do is analyze the specific seams areas, and ones that clearly have issues, as you go across them. For example, let's think of scheduling times. I believe that you -- that's somewhere where you can be very prescriptive, that you would be in a situation where if you were going to schedule across an area where you're going to have minimum scheduling, whatever, it has to work, because the generation's going

to want to move from one location to the other location.

As you walk through, I think you can perhaps be less prescriptive -- and I heard we clearly have a disagreement on whether the fact that the day-ahead market is needed. There clearly is an opinion by the three market operators that it's needed in the Northeast. Will the market participants in other areas of the country believe that is needed? And it may prove that they're wrong.

I don't know that it doesn't create a problem at the seam. If it is not defined as creating a problem at the seam, then perhaps you don't need to be quite as prescriptive. You need to almost take each of the elements and decide whether it really will produce a problem for the market participants or not.

MS. SILVERSTEIN: Before we go to Reem and the other panelists, let me see if it is worth turning this issue around. Are there issues you don't care where it's prescribed? Are there issues on where only flexibility matters?

MR. BAKER: That's a very good flip, and I think, again, it needs to be done case by case, but going through -- the ones that you really need to have we would recognize being a market participant, being a person who is going to be a user of the RTO, we're going to want to

do it as well so we can do the business at the seam.

So I haven't gone case by case down through it, unfortunately, to say this one, don't dare get prescriptive on, but I think that is something that the market participants in a region will work out with the regional transmission organization that they are parties to.

MS. FAHEY: I guess my comments would be brief because I believe you have to standardize the market in the day-ahead market. I believe you have to at least do that part, and it's critical that you do that part. If you're going to have seamless ratings between two regions, I think it has to be very clear what this Commission expects. And when we allowed people to, you know, have this case-by-case basis, whether do I need the day-ahead market or not, experience has shown that, you know, the operators say no, we absolutely need a day-ahead market and here's why. And I believe that the reasons why are very consistent with how we operate the grid, and they are consistent with all the reliability rules. So I think it both supports markets and honors, you know, the physical requirement of the system.

MR. CALDWELL: I think if you have a liquid spot market with arbitrage opportunities, to be able to arbitrage from that liquid spot market into forward

markets and across times and across spaces, that you will achieve what you want. If it is possible to do that without standardizing, fine. I don't know that that case has been made.

I think the case is clear that standardization of at least the scheduling protocols and all that is absolutely necessary. I agree with Reem that there needs to be an energy market that, as I say, is at least arbitrable across, and I think that means a standardized way of settling for physical delivery.

We also need to have a mechanism for solving the unit commitment problem, and the way that has been demonstrated is a day-ahead market. If we don't have a market for day-ahead market commitment, I suppose people will have to commit administratively, the way we used to do it. Either we do it by the market or administratively, but we have to solve the problem.

We don't have inventory to draw on in real-time. Therefore, we need to do that, and if there is something that can be nonstandard, fine, but let's make sure that we do not, in the result of creating something nonstandard, that we lose the liquid spot market, that we lose the commitment function. We have to have those.

MR. O'HEARN: I am a fan of standardization to the extent it can be done. If there was one seamless

market across all the North America, that would be preferred. For someone like us, there is, of course, differences regionally that would have to be looked at. Look at the example of hydro.

There's, of course, differences between the hydro in the Northwest and the energy in the Northeast, that if you were to design something standard that was maybe focused on PJM, you would lose some of those differences in the standardization, and then maybe the systems wouldn't be operating as efficiently as they could in that region. So to the extent that it's possible to standardize, we're all for that.

MS. SILVERSTEIN: So your answer is standardize except for very specific exemptions that are justified by local or regional needs such as hydro?

MR. O'HEARN: Yes.

MR. MEYER: I guess being more of a national player, we're very supportive of standardization. Many of the items, I think, that are going to be required I kind of refer to as more of the commercial practices, and hopefully we're taking actions to create a standards body which is going to deal with those and make those fairly uniform. Scheduling's been mentioned. That's obviously important, settlement intervals can be extremely important between all the regions at least that are fully

interconnected.

So I think it's got to be handled that way. I think if you can allow flexibility, that's great, but I think one of the problems we've had in the past, there's too much flexibility, and things don't match at all, as you cross from one area to another.

MR. BITTLE: This one is one that I know I've got to have standards, but I like to be flexible about them. It is one of those things that if you're transacting across two regions, there has got to be enough capacity ability there that you don't always butt your head against the wall.

Now, that obviously says in the long term that the more standard, the better. It's one of those things that what you're talking about are products, basically the way they're transacted, the time frames, and those kinds of things.

Now, there needs to be enough flexibility that you do not preclude the development of new products. That's where the flexibility needs to come in, because there's always going to be somebody with a better idea, and you need to be able to take advantage of that.

MR. KLEINGINNA: With respect to this -- and being at the end of the table, I've had an opportunity to write some things down, but I think that if we get

prescriptive on trading hubs and don't allow trading hubs to develop where they logically belong in terms of the market, we're going to do ourselves a gross disservice. I don't think that it particularly makes sense to be prescriptive on demand-side response.

I think there needs to be some significant flexibility with that. Not everybody is going to fit into the nice 50-megawatt block that I can offer to the marketplace. So I think that we absolutely need to be flexible and not say we're going to sell things in particular blocks to the marketplace, and there has to be some -- there may have to be some different types of operational flexibility there. Some folks may not be able to get off in an hour's notice, but there's still an extraordinary resource. Some people may be able to get off in five minutes' notice, and they should be rewarded for that.

I think with respect to demand-side response, sitting in those shoes as I do, we probably need to have some flexibility there. With respect to things that we have to be extraordinarily prescriptive on, I think, you know, operationally that makes a lot of sense. I think with respect to transmission rate design across RTOs, that makes a whole heck of a lot of sense, and I certainly believe that with respect to losses, we need to be

standardized and fair. And that's pretty much what I would say.

MR. BROWN: My written comments indicate that, obviously, we believe compatible technical standards across an RTO would be good for further development of demand-side responsiveness. I accept the caveats expressed by my colleague on the right that there are a variety of products that, in this new arena, we need to allow to come into being, but we need to promote open architecture software, competent measurement units, as we've been discussing, and that would include time increments to facilitate the regional trading of demand resources.

MS. SILVERSTEIN: If I may ask one more.

MR. KELLY: Sure.

MS. SILVERSTEIN: There have been several comments from a number of you about demand response is good and things that should be put into market rules have been referred to in different levels of detail, but let me ask you to be specific in terms of the following: as you look across the ISOs and markets that are in place today, could everyone who has a stake in intermittent or demand resources who is a panelist specify the two most important measures that you see in markets today, in market rules that you see as impeding the effective participation of

intermittent resources and/or demand response measures in wholesale markets.

MR. CALDWELL: If we have a liquid spot market in which we can settle that spot for our imbalances, if we have flexible, near real-time scheduling, we can work it out. The rest of it, yeah, we may be arguing about for a long time, but at least we can physically deliver our product and we can exist and we can improve. If we don't have those two things, we just simply can't.

It seems to me it's funny, because I'm not sure whether Kevin stacked the panel or what. I think there is a reasonable consensus among the panel about those issues, but when you go out in the real world, those conditions simply do not exist in 75 or 80 percent of the country. It may be we only recently have come to this consensus. I am not convinced. I think there still is a lot of work to be done, and I don't think we're there or anywhere close to being there a lot of places in the country.

There are a lot of tariffs being worked on right now that are about to be submitted to this Commission that don't meet those requirements or those standards that we're talking about here. And I think it's going to be very important over the next six months for the Commission to send those kinds of signals that they want to get there now, that we're not talking about

letting a thousand flowers bloom, we're not talking about getting some more information, we're not talking about five years down the road, we're talking about now. And if we don't do it now, we're going to have to do something about it.

MR. BROWN: I have a similar concern that we need to establish a clear blueprint for the DRR markets now. We need a structure, rules, and procedures for DRR participation now. We need clear tariffs that provide appropriate competition. We need a certainty that if you participate, you can recoup your investment. So we're in need of guidance at this point, and we need it quickly.

MS. SILVERSTEIN: But do you have two specific items within the existing market rules that you can point to as being problems that need to be fixed?

MR. BROWN: Our written paper provides about 40. So I would have to go to the top of the list, getting the day-ahead opportunities under control and universally applied, and then the flip side of that, we'd like to see price-taking provisions immediately.

MR. BITTLE: I guess we don't really participate in those markets yet, but we are affected in both cases. Basically the one thing we see that will have to be there is the ability to participate in real-time and have those deviations caused by those things that are

settled at the spot market price and unmet opportunities.

MS. SILVERSTEIN: Mr. Kleinginna?

MR. KLEINGINNA: I would say that -- this is not from Ornet's experience. Ornet has been able to participate successfully on the demand side. So I would have to share somewhat anecdotally the kinds of things that probably are a concern and came up at the last panel I participated in.

Commissioner Massey had asked if we expected to be compensated for providing these services. And the answer to that is absolutely yes. I think that to the extent that the tariff does not allow for compensation as if we were providing energy at the margin, that would be a significant impediment to market -- to demand-side response.

I think that that's extremely important, and I'm a firm believer in the market, to the extent that we regulate the price signal out of it, we won't see demand response.

MS. SILVERSTEIN: Mr. Meyer, any experience from ERCOT you'd like to share with us on how to accommodate wind in demand response?

MR. MEYER: I think it's already been covered. ERCOT has balanced schedules, and they had to do, I think, some special considerations or special resettlement -- I

shouldn't say resettlement. I should say special settlement considerations in how they approached the wind and -- I don't think we have solar. It's basically wind resources -- such that they're not overly penalized when they're off schedule. Basically, we give them, I think, a wide deviation that they can go between and allow them to adjust. They can't be treated necessarily as a totally controllable resource, so your market has to be designed to allow that.

MR. O'HEARN: If I could speak a bit to both sides of it, we have industrial customers through bilateral contracts and tariffs that we've used to give us more energy and capacity to sell into U.S. markets. We can basically do that because we have a portfolio of assets, and we can provide a lot of the ancillary services needed to do that. We don't have some of the same challenges that a lot of these other folks have.

We've also seen the other side of it, been a victim of demand-side management where in the Northwest there's been spells that have been brought down, and that was to produce extra capacity and energy within a region, and seeing the unforeseen consequences of actually reducing net capacity in a region. I wonder if some people here can talk about this some more.

We talk about who gets the benefit of the

demand side? Is it the incumbent utility or is it the load themselves? The question you have to add to that is who pays the consequences of that demand going down, if it affects transmission limits.

MS. FAHEY: I think one of the largest obstacles, not necessarily for intermittent generation, but for other types of generation, too, is the currently absent RTOs, is the physical requirements for transmission, and I think that's really the largest obstacle, because if you're an intermittent resource, you're generating now. You're not going to be submitting an Oasis request to buy transmission and have somebody evaluate it and tell you in 20 minutes whether you have -- whether you can get grid access or not.

So I think from our perspective, whether it's intermittent or just applicable to all types of generation is that the physical requirement of transmission becomes a huge obstacle.

MR. BAKER: I think Jim raised the question earlier about why we aren't further along, and I think the debate is -- and hopefully it's worked -- it's been better developed in the RTOs that are up and running. It's the question of putting equal on an unequal playing field and how do you make sure that you put demand on an equal playing field with fair rules and not overly advantage the

demand to the detriment of the generation. And I think the group around here would agree that that needs to be done. It's just a question of how you get that accomplished.

One question that I have for the gentleman at the end was that I thought he said that there had to be a design of tariffs -- and I may have misunderstood -- that guaranteed return of investment in demand-side products. I kind of question, do we have a market if it produces guarantees?

MR. BROWN: I apologize if I conveyed that misimpression. The objective of people participating in a market is to obtain value for their participation in the market, whether that's services or products. And so the people that are holding back entering the demand resource market in significant measure are, in effect, withholding their business activity. I called it investment by misdirection. I apologize.

MR. KELLY: Are we ready to move on? I know several people have questions. I'd like to give some priority to people who have questions about reserves, an important topic for the panel that we haven't gotten to yet, and we're a little low on time. Either of you have questions on reserves? Dave?

MR. MEAD: This is actually partly a question

about reserves and partly a question of what we were just talking about. So hopefully we can merge the two and satisfy Kevin. I want to pick up on Mr. Caldwell's concern about real-time penalties. There are really two questions.

First of all, what do you mean by a penalty?

Is any settling of the real-time market outside of LMP considered a penalty? I raise this because there's one view that suggests that when people show up in real-time unscheduled and without instruction from the ISO or the RTO, that the RTO has to incur some additional costs, like operating reserves, and therefore, is including whatever these costs, including perhaps some share of operating reserves, is that considered a penalty that you find troublesome?

And after you talk about that, I'd be interested in any other views on the issue of real-time penalties.

MR. CALDWELL: People always talk about that, and every time they go to try to find those and define those, they tend to go away. What we found is that every time you actually sit down and try to calculate how much it really cost, okay, we can always live with the result that what tends to happen is as people make these sort of arbitrary assumptions about things that are based upon --

I don't know, based on fear, based on lack of knowledge, and they come up with surrogates for saying what things actually cost, and those turn out to be penalties.

There's no doubt that it would be better if wind was a dispatchable resource. Clearly dispatchability has a value. Except that what we tend to do is we tend to overvalue that, and what I think we need to have is we need to have an efficient reserve market, that where the market design does not require additional reserves by requiring balanced schedules, and that where the reserve markets, you know, actually do reflect some costs.

There was an interesting piece of work that was done a couple of years ago. I think it was by Cambridge that looked at -- I remember specifically the graph that looked at market volatility on the Y axis and looked at reserve margins on the X axis and said how do different market designs perform as things begin to get tight, as reserve margins begin to be reduced.

And what they showed was that the outlier at the time -- this was about three-year-old data -- happened to be PJM, where PJM, for some reason, was able to operate a market without volatility, without price spikes at lower reserve margins than the rest of the markets were capable of at that time.

And I think it's those kinds of things -- if we

end up actually costing something, in terms of regulation or something like that, then charge us, but make sure that it is actually calculated and isn't just sort of assumed and it's arbitrary.

MR. KELLY: Alice?

MS. FERNANDEZ: Kevin and I were conspiring to shift this over to operating reserves. I think I will take the lead from Alison and ask some general questions that we could get all the panelists to talk about. I know a few of you talked about reserves, operating reserves in your opening statements, and a number did not.

I guess I'd like to ask a couple of key questions. First is whether or not the Commission should standardize on either having or not having specific operating reserve markets on day 1 of a standard market design. If you think there should be standardization on specific operating reserve markets, what specifically products, is it spinning in regulation or should other ones be included?

And also, if there is this type of market, what type of payment should be involved? Should it be something where there's a capacity availability payment or just for energy when called upon?

I guess also for those who suggest we don't need to standardize on day 1, another question is, is this

going to create any seams issues if we don't?

MS. FAHEY: I was the one who said that the Commission should standardize that, not holding up the whole market design because we're trying to get everything perfectly done on day 1. And I don't want my comments to be misunderstood, as a reserve market or ancillary market are not important. I believe they are very important, however, they're very complex. And I believe there are components that we know they work well, we have enough experience with and we can standardize that, and let's go ahead and do that.

Specifically, I would like to address the region where I'm from, which is the Midwest RTO. That spans four regional councils, MAPP, MAIN, ERCOT, and potentially SEP. The way it works right now is the regional reliability council determines the quantities, the levels, the locations, and so forth.

And I think it would be a very big mistake for the RTO to say okay, we're going to implement LMP a year from now, and we're going to employ operating reserve that same day as well, because we have absolutely no experience of what the congestion patterns would look like, because we have no experience with LMP. So I believe that we need to get -- we sort of need to get a year of experience on doing that.

And the reason why I don't think it should be done on day 1 is it's not a very large part of the market. Again, it's just get the 90 percent focus on getting what's really important on day 1 and phase it in. I know that PJM has sort of done that approach, and it works well.

MR. CALDWELL: I think if you have a standardized design, that the reserves sort of fall out, maybe at least notionally the difference between those two, and that there is more room to leave some differences in reserves because reserves tend to be localized, and therefore, they don't tend to get shipped very far, and that you can tolerate more diversity, if you will, in terms of definitions of reserves than you can in terms of energy.

Like I say, I think if you do solve the commitment problem with the day-ahead market or if somebody's got a better idea, fine, let's get it out there. And if you solve that and if you solve the dispatch problem and you integrate those two, then the reserves tend to fall out of that.

MR. O'HEARN: I think a third party could provide the operating reserve. It doesn't necessarily have to be the RTO. So as far as standardization, there should be some level of standardization, but again, there

is regional differences.

One good example is with hydro having the energy bid and spinning reserve -- sorry, having the energy bid in the stack for spinning reserve may not be something a hydro resource would want to have; i.e., they're willing to provide the capacity, but they don't want it in real-time if there's a need for their energy to actually be called upon, unless it's a reliability issue. So they like to separate those two. Whereas if you're in another region without hydro, it doesn't make any sense to have those two separate. You'd obviously have them integrated.

MR. CALDWELL: Let me make one amendment. Whatever you do, make sure you end up sharing reserves. The whole reason why, if you go back in history of the grid, why we got interconnected in the first place, was so basically that we could share reserves, and if we end up with a result where we don't share reserves, where everybody hoards their reserves to use for themselves, then I think the system is going to end up inevitably being of higher cost than the old one. And I don't care what else we do, we're not going to make it.

I remember the cost benefits analysis for Order 888 where, you know, they tried to at least model where are these savings going to come from, and the only place

that they could really come up and calculate savings -- now, that's a model, but still -- the only place that they could actually say where the savings from competition were going to come from was by reducing reserve margins and by allowing the system to operate with less reserves at less supplier capacity, less idle capital, if you will, to operate the system.

So whatever we do with reserves, we've got to end up sharing them as a result, which may be a little bit of a segue back from what I said, that since you don't ship them very far, you can tolerate differences. But still you have to share them within the region.

MR. O'NEILL: Can I ask a clarifying question for Danny? You said that RTO versus third party supplying reserves. Ultimately, I would think third parties are the only supplier of reserves; if the RTO does, it's on generation. The RTO can run an auction market to procure those to make sure they're in the right place. But did you envision that the RTO would actually own reserves of some sort?

MR. O'HEARN: No, I was more talking about actually running the auction itself, that that could be done by a third party.

MR. O'NEILL: And the difference between an independent RTO running that market and a third party

would be?

MR. O'HEARN: One, the cost of putting that market together and some potential that they could respond quicker to changes in market needs for products.

MR. O'NEILL: Do you have a little bit more detail?

MR. O'HEARN: I could provide something afterwards, yes.

MR. MEYER: I guess I'm going to take a little difference of opinion here. I think the operating reserves or what we call needed reserves for operations are not separable from all the other markets necessarily.

While I'm not sure whether the RTO has to run the actual auction market itself, it has to be a centralized mechanism. There's three basic things that you have to have as an operator: you have to have spinning reserve, you have to have regulation, you have to have reactive capabilities. Reactive is so localized, it's probably best handled differently. I don't want to lose sight that that should some day evolve into a market, and certainly, it is a value that needs to be paid for, someone supplying it.

Spinning reserve and regulation -- and I think regulation ought to also be broken down into regulation up and regulation down, such as we did in ERCOT, and the

basic reason is that a fully loaded unit can supply regulation down. It can't supply regulation up. So if you make it bundled, you will eliminate units from being able to bid separately.

Now, if people argue with that, and I do agree, usually a unit is loaded such that it can do both, and obviously if it can do one, it can do the other, usually, unless it hits a sustained limit low or high. I think what we mean by reserve sharing -- and I want to explore this a minute.

In Texas we have what we call self-arrangement. In other words, participants, load participants are assigned an obligation to supply reserve. Someone has an obligation. You can either let the RTO purchase it for you and you pay the clearing price of that, or you can provide or arrange for it yourself.

I think what we mean by sharing in Texas is we also -- we have to -- you can arrange for it, but you have to give it, for control, to the ISO. You don't get to deploy it directly. It's deployed for the benefit of everyone. It can be self-arranged.

And in fact, in our -- and our typical requirements on reserves, spinning is about 2000 megawatts. Typically the ISO will very seldom buy more than 400 or 500 in the market. The rest has been

self-arranged. And the requirement for regulation now is selling in at around 1200 megawatts, and usually he will only buy a couple hundred of that. Almost all of it is self-arranged usually.

MR. KELLY: John, just a clarifying question.

These requirements you're talking about, are these Texas PUC requirements or requirements developed by the RTO under an umbrella regulation set out by the PUC?

MR. MEYER: The RTO, or ERCOT, set its own requirements of the levels. They have some guidelines developed in protocols by the stakeholders committee for reliability. So basically, they have to follow certain NERC requirements, and to do that requires certain levels of reserve. ERCOT spinning is probably higher than anyone else because it has an isolated system. So in order to be able to recover frequency in a fast enough manner to meet the NERC criteria, it has to be a little more reserve out there.

But these are set by the ISO, and they change.

Typically the only one that changes a lot is regulation, and it changes somewhat seasonally, and also with what he envisions is the variations in load or the slope of the load coming up and down in the day. If it's flatter, he obviously probably needs less. If it's very steep up and down, very high peaks in the day, then he probably needs

more regulation, and he makes that call.

He posts that the day before, signs the obligation based upon historic, last week's load forecasts, and everybody knows they either provide it or they just go to the market and let the ISO provide it at a price. But we found that very effective, and those are the minimums.

The other reserves I talked about in my opening remarks, they're important: replacement, nonspinning which we classify as 30-minute, others classify at different levels. But I think those can have some degree of regionality or flexibility, because they're more concerned with replacing reserves that have been lost. And they're heavily dependent upon how you set commitment and really your protocols, whether you're going to have more or less committed on a given day.

For instance, even though Texas has nonspinning, very seldom does the ISO actually go and buys it, or replacement for that matter. He usually has more capacity, he thinks, committed than he's going to need to worry about. If he's very tight, then he's going to have to worry about lining up additional supply.

And that's kind of my take on it. I think it ought to go in, at least these basic ancillary service markets, day 1 with the ISO or the RTO start-up.

MR. BITTLE: I think that when you look at the historical way the system's been operated, I think that you can see the need for these has always been there. The question is, at what level? And there's a price. The more you have, the more it's going to cost. The lower it goes, the more likely you are to have an outage.

So it is one of those things that there's some range there. Obviously, you cannot get by with zero spinning reserves, but how high above that do you have to go? That's one of those things that eventually, I guess, the market will have to really decide.

Part of it is, how do you procure these and how do you charge for them? To some extent some of these are going to -- as you're a part of the interconnection, the interconnection's going to provide some of it. So for some entity to, you know, really charge a specific customer for that, there's -- when they're not necessarily the one providing it, really starts to raise some questions.

So it is something that you owe to the interconnection, and I think as the interconnection looks at that and they provide that to each other, there is a benefit. That's where the sharing comes back. There is that community aspect to this that lowers the price to everyone, and as you share those, you can get by with

less.

But, John's right, you have to make it available to the RTO who is going to actually react to those kinds of things. When you start talking about some things, you're going to have generation deviations that are caused by the interconnection, not just by your own load.

And so there's some of these things that where they're going to wind up long-term still remains to be seen, but how you procure them, in some cases all you're doing is asking who is willing to provide those. And you can get that by paying a capacity payment, and once you make the capacity payment, the energy ought to come with it, basically at cost, in my opinion.

So there are a lot of things that have to be discussed, but where they're going to finally wind up, that's not quite clear in my mind yet, but there have to be those kind of operating reserves, and they have to be available for use by the interconnection.

MR. KLEINGINNA: With respect to operating reserves and ancillary services, it is not an insignificant part of my power bill. It's seven figures on an annual basis, and with respect to standardizing the requirements, it seems to me, as someone who has to operate and be responsible for reserves as a holder of a

transmission contract, I would push for standardization, at least across the interconnection, first of all, to facilitate my shopping for these reserves.

Secondly, it would let me know what my requirements are going to be for reserves so I can make a decision as to who I wanted to buy them from the market or self-supply them or potentially supply them to others as a load.

So I would say that it seems to me I'm in agreement with John Meyer on this, that you want to do this at the same time, because for my pocketbook -- not my pocketbook. My corporation's pocketbook, it's a large issue, and it's a large dollar issue, and I would like to know what the opportunities are across regions.

I also think that to the extent that you have differing requirements or you don't have standard markets, you once again can end up with suboptimal solutions, where some folks are self-supplying in, say, Maine and others are buying from the market in PJM. And that might not be the right thing, if you had a standard market, you might be able to dispatch on the load side or even on the generation side more optimally, because different rules lead to a suboptimal solution.

That's what I've got.

MS. SILVERSTEIN: Before Mr. Brown answers, I

wonder if I could ask a quick question for you to address and everybody else to come back if they feel they have a contribution to make. Everybody who has answered this question about operating reserves thus far has dealt with entirely supply resources.

MR. BROWN: Thank you for the opportunity to address that question. The ISO New England now has a replacement reserve opportunity, that demand resources participates in. I'm going to use it as a piggyback opportunity. It's a 10-minute operating reserve. And one of the things that becomes evident, when you examine what ISO New England does with respect to replacement reserves is, they commit about 1000 megawatts daily for the purpose of having sufficient committed capacity in the event TMOR isn't met the next day.

The interesting fact is there's no market, there's no payment, it doesn't arrive at the wholesale generator, it doesn't arrive at the demand resource.

And one of the immediate agendas that we would like to see addressed is that that be given value and that that be given an opportunity for demand resources and the wholesale generator market to be compensated for providing that 1000 megawatts of replacement reserves every day.

It's one of those things hidden in the structure that isn't monetized that if it were monetized would give us

all something more to work with. Obviously, ISO New England has a variety of methodologies in place, et cetera, which you could address, but that's just from the participant's standpoint. There's an opportunity that we'd like to address.

The operating reserve markets, we definitely believe the demand resources can meet the 10-minute -- you know, at the various levels that we've described. We started negotiating on these, for example, in the New York ISO structure in early 1998 in the design phase of the organization. And while there was some whopping good negotiations about the way distributed resources could fit in, when it got down to the software design of the system, well, we can't quite cope with all those little guys.

We can't quite cope became a mantra that continued for three years in the form of well, there aren't enough buses in the computer software to allow dispersed resources to participate. There are only 50 buses available, even through this past year.

Well, FERC has moved to change some of that, and obviously, software configuration needs to be standardized to permit multiple players to enter the markets and bid as well. So we definitely think these are markets within reach. The technologies have improved for communicating with them. The resources can respond.

MR. KELLY: Mr. Baker?

MR. BAKER: I think one place we may be getting confused is whether there's a market for these reserves, just as a general rule, or whether it's the same exchange or a similar exchange to the hourly spot market and day-ahead. I believe that we need to self-supply the ability to do that.

I also think that the RTO needs to go out and contract, if it's not built in day 1 -- and I think it does get complicated if you build it in day 1 -- along with everything else, in a place that already doesn't have a tight pool and have an exchange already built in, that building reserves as a part of the exchange could result in a suboptimal answer for the energy market day 1.

I think we saw initial problems up in some of -- in the New Englands and the New Yorks. I think they've overcome a lot of that, but initially there were some problems of the interplay between those markets.

I think you can create the situation where the system operator can actually go out and request bids. And they may do it on a day-ahead basis, a week-ahead basis, a year-ahead basis for these reserves, get the lowest supply, get someone who can truly respond to their actions, and you have created a market. You just haven't necessarily linked it to the hourly energy market.

I think ultimately you want that linkage, because it really is, to a great extent, all energy related with the exception of reactive as mentioned. That has some special characteristics, but ultimately, you want to get there, but I'm not sure that's necessary day 1.

And to answer the question about demand side, it may actually be easier for a demand-side participant to enter into a contractual relationship where they know what their requirements are going to be going forward, as opposed to trying to bid them in in the short run into these markets and have to react during production cycles that may not work as well.

MR. O'NEILL: Why wouldn't you allow both? That's not an either/or. They could contract for demand response, or they could bid it into the market, either one. Why would you limit it?

MR. BAKER: I'm sorry. Limit --

MR. O'NEILL: I got the impression that it was an either/or proposition. You would contract, but you wouldn't bid into the --

MR. BAKER: No, they could definitely bid into the market. They may choose to take their optional amount that they could move and save it for bidding into the energy market, or they could have contracted in a relationship with the system operator to provide reserves

at their call. Either one. I'm sorry if I --

MS. FAHEY: I just don't want my comment to be misunderstood, that I don't think the RTO should, you know, offer operating reserve or run an operating reserve market on day 1. I believe that that's, obviously, necessary and needs to be done. It's part of the reliability components that the RTO has to administer.

My comment was I believe we should not get bogged down in trying to get a standardization of what the level of operating reserves should be and the amount of reserves should be and the location of that should be. So I just wanted to -- because I don't know if Mr. Meyer misunderstood my comment. The purpose is not, you know, we need to get what we know about done as soon as possible.

And I can assure you, within the Midwest RTO market, we have four different reliability regions. They all have a different way of calculating reserve, where it's located. They have different requirements and criteria for deploying it and for replenishing reserve.

If we're going to wait to implement 90 percent of the market until the four regions reconcile the requirement, we'll be stuck here forever. We'll be talking about this three years from now. I just hope that will not become an obstacle in getting most of the things

that need to be standardized done as soon as possible.

COMMISSIONER MASSEY: I have a question.

Should we at least require a market-based approach,
whatever it is?

MS. FAHEY: Absolutely, yes, I believe in
that, but to me, standardizing operating reserve -- and I
think I would like to share what NERC attempted to do in
NERC Policy 10, which never became a policy. That's what
happened. We got bogged down in the industry of what's
the level and how do we deploy it and who carries it and
who pays for it.

We just got so bogged down on these
requirements that NERC Operating Policy 10 never became a
policy and sort of got put on the shelf. Again, it's a
huge, complex issue that, you know, we ultimately need to
deal with it. I absolutely agree it has to be
market-based. The RTO should then say the vertically
integrated entities always procure reservations from the
entities, and I'm going to allow that. That's not what
I'm saying.

MR. KELLY: We have two former system
operators, Reem Fahey and John Meyer, one who says we can
delay it and the other, I understood to say, we can't.
Could I invite you two to just talk to one another and
we'll all listen and hear where that conversation goes.

MR. MEYER: I will try to address that, although I had a couple other points I was trying to catch up to that had been asked, that I haven't got to speak about it. If I may kind of take them in order. Real quickly, just following up on what Craig had said, I guess we had real concerns of the RTO entering into long-term contracts for supply.

Basically, the RTO should not be taking a position in the market, if he can help it. He's conducting a lot of auctions, and he's taking, I guess you could argue very short-term, but let's keep them to real short-term positions. If he takes a long-term position, he may as well become a utility eventually and just supply all the load himself. So I don't think that's what we're after. He's an administrator. He's not a position-maker.

The second thing that was asked about loads, in ERCOT, we allow -- loads bid very effectively in the spinning reserve markets. We have somewhere around 3000 megawatts of interruptible, large industrials that can interrupt and have done so under tariffs, and we have allowed that up to 25 percent of spinning reserve can be supplied on these contracts, and we're trying to stretch that to 40.

I want to make a key distinction. You say why not 100, because I've had a lot of people say why not just

let them supply all of it. Well, the spinning reserve serves multiple functions. It's local speed control on a generator basically. So it's following frequency or deviations in speed constantly. A load that is tripped, either by underfrequency or some remote initiated signal, is not going to follow that same responsiveness. And so you have problems if you want to go 100 percent with loads.

So there is a -- plus, if you set it, like in Texas, we set it under frequency trip, you could have overresponse. That's one reason we try to limit how much is on at one time, because if you trip 500 units, you may trip 1000. You've got to be careful you don't overspeed. So you have two issues.

That's all I really want to say, but there is ways to deal with it and let load go into those marketplaces in capacity.

MR. KELLY: Thank you. A really basic question for us, as we think about proposing a rule on standard market design, is whether the various operating reserve markets should be integrated in or delayed in their implementation. You can't get too much more basic than that.

MR. MEYER: Right.

MR. KELLY: At least I'm confused between what

I hear from two former system operators --

MR. MEYER: Let me address that. I think what Reem was trying to say, she doesn't say the reserves aren't needed, she's saying delay a full market implementation for some period of time using an alternate means, which would be just a straight-out commitment of generation.

I mean, there's many ways to have it. I don't think she's saying we can just bypass reserve requirements, because they are absolutely required.

MR. KELLY: And you said --

MR. MEYER: I said create the market up front.

MR. KELLY: -- reserves are not separable from other operations?

MR. MEYER: They're not easy to separate. They can be. I think PJM started out with that approach where certain reserves were a requirement of supply, which is very typical -- I mentioned a reactive right now. That's a condition for interconnection, the way it's been preserved in the past. Although it is a cost that a generator or somebody else is incurring, it is uncompensated for.

MR. O'NEILL: Can I see if I can clarify in my mind? I think that both John and Reem don't disagree that in the long term, we can integrate these markets, but we

shouldn't delay getting started if integration is a problem.

MS. FAHEY: If I could address that, as we were trying to design the Midwest RTO market -- we got bogged down for, you know, umpteen hours trying to resolve this, and in my opinion, the best solution was okay, we will solve it a year later, but let's not -- let's get the spot market and the day-ahead market working, because that's the biggest benefit for everyone.

So in no way am I implying that the RTO should not be running this market, absolutely, and I think they should run it in a year, no later than that, that it has to be market-based, and every generator should be able to bid into it. I'm just urging you not to get bogged down in that, because then every regional reliability council is going to say no, my solution is the best, and let's go with what I have.

MR. KELLY: So when Mr. Meyer says the two markets are not easily separable, does that fit with what she's saying, in your opinion?

MR. MEYER: I'm not sure where Reem's totally coming from. One of the problems, I think, may be whether you have one control area or multiple. When you have multiple control areas, you have quite a disagreement or quite a, I guess, compromise on who gets to control what

functions between an RTO and a control area operator, where if you have a single, like PJM, ERCOT, California, it's rather obvious who is going to have to do the control over the units or basically deploy the reserves.

It has to be the RTO, period, because he has the control area operations also. And I think all Reem's trying to say is in her opinion, she can -- you can delay that function and go to an alternate means of supply. What I'm saying is I'd rather not do that up front. I think there are market mechanisms. In the start-up of ERCOT, I do not think that was a limit at all in trying to set up the reserve markets in that. In fact, I think that was the easiest part.

MS. FAHEY: If I could quickly reply to that.

MR. KELLY: Very briefly.

MS. FAHEY: I think John said exactly what the problem is. That's not what we have in the Midwest. We have multiple control areas. Unless the Commission is going to dictate one control area for the RTO, then I'm all for it, but that's not the reality that we have, and we have four different regional councils.

So, you know, what was achieved in ERCOT was easier because of those requirements, which is not what we have in the Midwest.

MR. KELLY: I want to turn in a minute to see

if people in the audience would like to ask questions.

You might be thinking of your questions, and we have people with roving mikes, which you will need to speak into to get it on the record. I know Udi Helman had a question he wanted to ask, and this would be a good time.

MR. HELMAN: Thanks, Kevin. This is a general question, but reserves could be fit into it. As we look at this sort of initial question of standardization, when you even look across the Northeast ISOs, there are a lot of differences that come out of regional concerns, and that has been one of the main reasons why people have resisted the notion of standardization.

At one level there may be philosophical differences, but then people think about their local needs and their regional generation mix and their transmission system and load pockets. And yet, when we have a discussion, people find it very hard to imagine a standard market design that didn't incorporate those into it. So there's kind of a fundamental tension there.

What I was wondering -- and obviously reserves is one component of this. PJM offers certain types of reserves. New England offers additional reserves that it feels it needs to have.

Should the standard market design basically try to incorporate, as we look around the country, the

localized methodologies for dealing with particular problems and then offer it to people as a sort of opt-in or opt-out basis, or should we stay away from defining processes for dealing with local problems? I can give you an example of those types of things if you're interested.

MR. BITTLE: Yes.

MR. HELMAN: An example, an obvious one, is the decision on which types of reserves to offer in different markets. Another one might be how you do hydro scheduling in bidding. PJM does it quite differently to New England. Should we look for the most robust solution to the problem of how you do hydro bidding and scheduling and put that in the SMD and allow entities to opt in and out, or should we sort of leave the question alone? You can spin it into a reserves question, if you want to keep on the path.

MR. BITTLE: It does have several impacts. To the extent that you're allowing somewhat of a regionalization where you're requiring it, somebody's going to set a minimum on what we're talking about, as far as reserves is concerned. Otherwise, I'm going to zero because I know the interconnection is going to support me. That's not the right thing to do, and everybody knows that.

It is one of those things that it raises the specter of either subsidization or giving someone a

competitive advantage. If I'm required to carry more than someone else or if I'm required to carry less than someone else, somehow or another, that's going to equal out over the interconnection, and it's going to -- but as long as we're all carrying about the same, that's all right, but it does raise that idea.

And so to some extent, requiring that gets back to some of the local questions. What is the generation mix in that area? It will affect what the reliability of that area is. What are the congestion points in that area? Which means that you've got to have generation on both sides of it in order to really relieve the congestion. So there are things like that that have to be taken into account that are local in nature.

MR. HELMAN: And the question is, should the standard market design stay away from those issues, or should it look around the country for the best ways that different regions have come about in dealing with those issues and put them there as a starting point?

MR. BITTLE: I think they have to be dealt with, and obviously the best practices is one way to start.

MR. MEYER: Just a couple of comments, I think where you deal with localized exceptions or exemptions, you have to be very careful. One of the things we were

real happy about in ERCOT was that everybody came into the control area, unlike California where you have big holes in the control area of large municipals that did not go in, and I think that creates more problems than would have been otherwise if they had just come in.

One thing Ricky said very important is that it can, and often does, create some cost shifting when you do standardization across a wide region, because some people are used to one way of doing it, and others may be a different way, and there's going to be a shifting of responsibility in their cost to the market, and somehow you have to consider that when you're doing it.

As far as hydro special conditions, I think hydro and what I call environmentally limited units or units that can only run so many hundreds of hours a year because of requirements of law fit into the category of what I call energy limited units. As someone mentioned earlier, if you do not provide opportunity cost to those type of resources, you're going to have a very basic problem of the valuing of those resources in the market.

I think you write the rules with that in mind, that they have to be treated such that they're looking at forward opportunity cost, but you don't make a lot of other special exceptions. Every exception or every rule you make creates an incentive. Many of them you won't

even recognize until many years down the road. So try to minimize differences, if you can.

MR. KELLY: Reem, and then we're going to go to questions from the audience.

MS. FAHEY: I guess my advice would be that at the minimum, FERC should mandate that within an RTO that you give them a time period. I think it should be no longer than one year to get at least uniform operating reserve within that region. Again, I'm more specifically talking about the Midwest, that I do not believe it's acceptable to have four different operating reserve requirement and criteria within the same footprint of the RTO.

So I hope that, you know, FERC would mandate that at least within the RTO, that there needs to be one criteria and determination of the local amounts and needs within an RTO.

MR. KELLY: We're going to take some questions from the audience. I would ask that each questioner give his name, affiliation, say which panelist you're asking the question of. Please, no questions to all panelists, or it will take 45 minutes per question that way.

MR. DESOVO: Fernando Desovo for FPL Energy. My question is directed -- forgive me. It's either Mr. Meyer or Mr. Bittle who, I believe, said that

locational marginal pricing identifies very well the load pockets or congestion, but does not provide -- at least the mechanisms that we know of currently do not provide the signals to mandate what is needed to resolve that congestion.

My question is, is it possible to somehow develop some incentives into whatever we develop in the rules of an RTO to provide those incentives, or is it your view that maybe we are relegated to today's environment where the only way that transmission or transmission expansion is going to be done is through the current rate-based-type mechanisms that exist to recuperate the investment? Or did I misunderstand what was said?

MR. BITTLE: You did not misunderstand what I said. I don't know how transmission is going to get recovered, but I know the LMP itself does not necessarily provide what is necessary, because as soon as you bill the transmission or put a generator there, the LMP at that location changes.

It's no longer what it was, and unless you have a good idea of what it's going to be, you don't have that. And so will there be financial incentives for transmission? Well, that's one of the questions that's out there. As soon as you put financial incentives for transmission, why not for generation. And so you've got

that competing question just automatically. It's just that I don't see how LMP itself solves the problem of load pockets, and that's where it really comes into play.

MR. KELLY: Another question from the audience.

MR. WILSON: Seth Wilson with Enron Market Corporation. A question for Danny O'Hearn with Powerex. Are you familiar with the Alberta ancillary service market design, and is that one example, when you talk about third-party market operators?

MR. O'HEARN: The Alberta Power Pool is right next door to us. I myself haven't for a couple years dealt with Alberta exactly. Their operating reserves, at least one piece of it, is done through an electronic exchange where it just allows buyers and sellers to come together there to create a market.

Sellers that have generation like ourselves might want to sell into that market, generators internal to Alberta as well as some of the other ties from Saskatchewan. On the bid side of that market, I think there's possibly people looking to arbitrage that market, but I believe the transmission provider is really the load side of that equation.

So that would be an example where a third party's efficiently bringing buyers and sellers together at a very cost-effective price to do that. Where that was

done maybe embedded into the transmission provider's structure, that will get ruled out. All the customers would have to pay that, maybe the customers that don't even -- that use those services.

MR. KELLY: Thank you. Another question.

MR. HUDDLESTON: Barry Huddleston from Dynegy.

I don't want to let John and Reem off the hook so easily on the reserve question. The question is, aren't you dealing different things? John was addressing the market mechanism for procuring the resources to provide the reserves, and Reem seemed to be addressing setting the level of the reserves and not trying to get a common standard across multiple control regions.

It seems to me they're different questions.

And the common standard doesn't necessarily have to be there immediately, but can't you have a common procurement mechanism for the resources and just apply the common procurement mechanism to the different standards across the control regions?

MR. KELLY: Reem, why don't you go first, and then John.

MS. FAHEY: And I think Barry qualified what I was trying to say very accurately, that the problem is the level. It's not just that. It's a bit more complex than that. It's the criteria. For example, let's talk about

an example between ERCOT and Maine. Maine allows you to
 lien on the reserves for an hour, ERCOT doesn't. It's not
 just allowable and it's not just the procurement. It's
 also replenishing the reserves.

So I think that the task, again, that the RTO
 has to offer entities to either self-supply on day 1, or
 if they can't, that the RTO would procure that and,
 obviously, share that among the whole participants. But
 getting bogged down again on exactly the same level and
 getting bogged down on what's the criteria that's the best
 for all four regions is not necessary on day 1, but has to
 be done within a year.

MR. KELLY: John?

MR. MEYER: I appreciate Barry clarifying that.
 I was dealing more with procurement. Of course, I had a
 couple basic assumptions built into that. One is that the
 RTO would call the amount needed, not different groups.
 Now, I think looking at trying to understand the issue
 better, I think I could go along with the transition
 period of how you specify what amounts and then let the
 RTO call it in a year or two. I think that's reasonable.

I'd be a little more concerned with my second
 issue, which is the standard products. If they're very
 different products, I'm not sure how they're going to work
 quite as well, and I was troubled also by something Reem

said in that it sounds like there are going to be benefits for the control area but not for everybody in the RTO.

In other words, it's shared by control area, not RTO. I want to be very sure that all the benefits get shared across the RTO, not just a single control area.

MR. KELLY: We have another question from the audience.

MR. LOWEN: I'm James Lowen from the California PUC. I had a question for Jim Caldwell. Maybe he could clarify something he said earlier, if I understood correctly. I think you said that the day-ahead market solved the unit commitment goal, and I was wondering, if in the absence of penalties for deviations, how that works.

MR. CALDWELL: I don't think deviation penalties have anything to do with the unit commitment issue and don't work to solve that problem. I think the -- what we were saying here is to use the day-ahead market as the mechanism to solve the unit commitment problem, I think, is generally accepted.

What happened in California was that the day-ahead market of the PX was separate. That created a set of separate issues. Then the failure of that market to clear pushed things into the real-time market, and things started to spiral away. So the failure was in that

market to clear. That market must clear, and I think that means that the -- that a function or a piece of the day-ahead market has to be that there is commitment adequacy in the day-ahead market, that you cannot allow unserved load to go from the day-ahead market into the real-time market, and that was the failure in California, and deviation penalties didn't fix it.

The deviation penalties just drove people out of the spot market and drove them to do a whole bunch of dumb things. But you have to have generation adequacy or adequate unit commitment, if you will, in the day-ahead market, and that was the failure in California, was allowing that under scheduling intentionally by the utilities, in many cases, to flow into the real-time market.

MR. KELLY: Final question from the audience.

MR. SOBIESKI: Dennis Sobieski from PSEG. A question for either Mr. Baker or Mr. Meyer. We've heard --

MR. KELLY: Without hearing the question, why don't we make it Mr. Baker in the interest of equal time.

MR. SOBIESKI: Fair enough. We've heard comments today, not from Mr. Baker, but from members of the panel, that you need to recognize regional differences, that yes, LMP works, but there may be other

tools that work.

And I guess I'm wondering if in the -- for the cause of getting the markets up and running and time efficiency here, whether there's a balance between trying to achieve up-front sensitivity to all of the market differences and nuances versus getting something up and running and being more standard on the global -- on the larger issues, like congestion management and transmission rights.

MR. BAKER: What I tried to indicate in the opening remarks was that we were supportive of some of the tools that had been proved to be useful in the Northeast and carrying them into other areas that are developing their RTOs. I do believe that you need to recognize the regional differences.

If you just took LMP as it was originally designed that assumed this single control area, it wouldn't physically work within the Midwest until you collapsed all the control areas. So I think you have to meet a certain minimum of those things, but you have to recognize that there are regional differences in order to make that day 1 work, and that's what you have to balance.

MR. KELLY: I want to bring the session to a close now. I wanted to thank the panelists for taking the time to travel once again to D.C., days when travel is not

that easy, and sharing with us all your thoughts. It's helpful for us to hear people discuss these issues, and I just want to express on behalf of the whole Commission our appreciation for you coming. Thank you to the audience for participating. The second panel will begin at 1:30 today.

(Whereupon, at 12:30 p.m., the hearing was recessed, to be reconvened at 1:30 p.m. this same day.)

AFTERNOON SESSION (1:40 p.m.)

MS. FERNANDEZ: Good afternoon. We're going to follow the same basic format that we did this morning, except this time I get to moderate as opposed to Kevin. The panelists are going to start off with a brief opening statement.

The topic this afternoon is transmission rights and financial rights. There's several things we want to get into a discussion of in this session. We had a lot of talk this morning and at some of our other conferences, we probably should discuss in terms of the transmission rights, if they should be financial or physical, both, within the RTO and there are also some questions in terms of, if you're going between RTOs, as to how those transmission rights should be structured.

There are various hedging rights being proposed. I know the Midwest ISO has brought up a variety of rights, flow gate hedges as well as point-to-point hedges. We'd like to talk some about whether or not all of those should be available, if certain ones should be available, how much innovation is necessary, how much flexibility should be allowed, how much standardization should be done up front.

We're also going to get into some discussion and I had to mention to the panelists that it wasn't

something we didn't say explicitly, but was rather amazed we hadn't. We'd also like to talk about the transmission rights or the financial rights and how they're allocated. In some systems, they're directly assigned. In other systems, they're auctioned. We'd like to talk about whether or not there's a preference or benefits to one versus the other.

Finally, one other topic that we'd like to get into today gets into sort of a general issue of expansion. We currently have several proposed merchant transmission line projects in the eastern ISOs where there are some issues involving what happens with the capacity that's created. And that is something, I think, we'd like to talk about, not only for Merchant lines, but perhaps also for additional capacity that's created as to how those types of financial rights should be handled.

With that, I don't know if there's a clear preference as to which way we start. I think maybe we'll start differently this time. Why don't I introduce Wayman Smith from Williams Energy Marketing. I'll let you start off, and then if we could sort of continue down the panel. If you need to introduce yourself.

MR. SMITH: Thank you. Good afternoon. Here I thought I sat on the right end of the table, and I found out I was on the wrong end of the table. It's a pleasure

to be here this afternoon. Obviously, I believe that the proper construct of a transmission rights market is critical.

I think one doesn't have to look very far to find, you know, article after article detailing the fact that new transmission construction has not kept pace with generation additions. Uncertainty over cost recovery, lack of incentives has stalled transmission construction. ATC has dried up in many parts of the country. It's difficult to get access to the grid. There is transmission congestion, and the problem's going to get better before it's going to get worse.

My view is that in the long term, the ultimate solution is to provide proper price signals to allow new transmission and generation to be constructed to eliminate congestion issues, but in the meantime, we have to find an effective way to allow the market to deal with congestion and to hedge congestion risk.

I was encouraged by the Staff concept paper. I think a market based upon LMP with forward transmission rights is the right way to go. I believe that provides the most basic fundamental elements that are needed in order to construct a market that will work properly. One of the issues that didn't take me very long to get to, but one of the issues associated with the allocation of

rights.

And I sort of liken this to being all dressed up and having nowhere to go. If we get the market design fixed, we have a workable market. All the elements are in place, and then we allocate all of the transmission rights to the existing holders, and guess what, there's nothing left to be auctioned or available in the market. That's one of my biggest concerns.

So I am obviously an advocate for auctioning all of the rights with the revenues back to the existing transmission service customers. I think that will help to improve liquidity in the market. There are other issues associated with liquidity that I'm sure we'll get into, but that's obviously a big one.

Another issue that maybe hasn't gotten a lot of discussion, but it is related to the term for financial transmission rights. I would like to see a variety of terms offered, not just monthly but also longer term, 6-month, one-year, three-year, five-year, so that the marketplace has those instruments available to be able to get certainty over a longer time period.

Another issue that was kind of touched on this morning with regard to LMP, the comment was made that LMP provides the right signals to allow market participants to make decisions regarding investments, but it doesn't

necessarily provide the solution, and, you know, there again, I think the issue of providing the right incentives to allow new transmission construction to take place is key to eliminating congestion on a longer term basis.

Thank you.

MR. WALTON: I'm Steve Walton. I'm currently working as a consultant for RTO West. Two weeks ago, we explained to you our concerns of fitting a new system, these new day ahead and real-time markets, for regions that used a large amount of foreign energy.

For that reason, we spent considerable time early on on a physical rights model because of some of the features it provided that were helpful to the system in terms of restraining or in constraining -- let me start again, in limiting schedules on constrained paths. We have shifted now to a financial rights model.

We could not make the physical rights model work for a number of reasons, one of which is when we tried to convert all the existing contracts, we ran into an enormous number of difficulties. And the second problem was we began to have rules mandated on top of other rules as they were layered up trying to deal with things like recalls and releases and so on. So we've shifted to a financial rights model, accept all schedules approach.

However, in designing the financial right of a transmission right, the FTR -- as we've looked at this, the FTRs as used in the Northeast that have a stream of revenues, hedges as they're defined, but they don't meet the revenue to put some tie between usage in an area that's going to have a large amount of sunk commitment.

As a result, Eric's proposal we have developed is based upon having options, forward options, not obligations but options, and that those options would provide a credit against the congestion costs the customer faced up to its full congestion charge, if it's that much. If the congestion cost is less than the value of the FTOs or the options, then we encourage the customers to -- or the customer gets that value to release them into the secondary market.

Another difficulty we have seen is we have looked at the financial rights that are just a stream of revenues. There's very little incentive, in fact there's some disincentives for releasing them to the secondary market. If you're a party that's under state regulation, you release them and you make something, it will be swept up. If you release them and made a mistake, they will dink you for it. The best bet is to sit on them and capture the revenues and saying that's the best we could have done.

The design we are coming up with hopes then to have the effect of doing two things. One of them is because there's a tie between usage and the value that it has to you is, even though it's a financial right, is that it encourages people to release those rights that they don't need.

Now, with regard to allocation, we have -- because Bonneville Power Administration is a huge part of the formation of RTO West and Bonneville has made a prerequisite of its participation with its customers a commitment that it will honor all of its existing contracts, and it has hundreds of them, with public power entities and with investor-owned companies and with others.

In order to do that and to release as much as possible, we came up with a method that we've called "cataloging" where we identify all the existing rights in a catalog, and then we pool them so that we can release as much as possible of other transmission rights to others. We just this last week added another feature to try to get even additional releases added into that process so that people would release and see the price and release it for cash and give their flexibility up in exchange for cash.

So while we think it's important to have financial transmission rights, the exact design that has

been used in the Northeast, we think, is not applicable to our circumstance.

MS. MANZ: I'm Laura Manz with PSE&G. I think it's important for us to start with whether you're using financial rights in the form of, perhaps, path rights or point-to-point rights or physical rights. There's only so much transfer capability in the grid.

And so I think the first part is to see, because we have a limited amount of capability, how do we convert things into rights, and if the goal is a robust, wholesale market, we want to make whatever product we're creating as flexible as possible and as amenable to markets. Financial rights are preferable over physical rights because they enable the system operator to do the least-cost dispatch, and this allows customers to be served at the lowest possible cost and still provide maximum flexibility to market participants.

I think every market should begin with point-to-point obligation rights that are financial rights, point-to-point obligation rights. Additional forms of rights can be added where they are technically feasible, technically accommodatable, and also where market participants desire them.

The important part to remember about this is that once you start offering different types of rights,

given that there is only so much transfer capability in the grid, you may have some liquidity issues in the market if you're trying to trade different types of rights across the same transmission system. So because we're not creating any additional physical capability, that's a factor to keep in mind.

On the allocation of rights, it's important that the rights be allocated to those who have paid for the grid, and so this can be done on an historic basis to look at the allocation, and that can be done in two ways. In PGM we started with allocation of rights that people just held. Another way to do it is to allocate the auction proceeds.

And so in either case, there is an allocation, and it just depends upon what's being allocated. But those who pay for the grid historically should be allocated the rights, and then on a go-forward basis can be also allocated the incremental rights for any new capability that's been made available by increasing the transfer capability.

It's important, I think, also that market participants either receive the benefits or bear the costs of having chosen the rights. So if they've made the right decision, they should receive the money, and if they've made the wrong decision, they should bear the cost. In

addition to that, the RTO itself should never be placed in the position of becoming a market participant in the rights markets or requiring -- being required to subsidize anyone who has chosen a wrong set of rights.

And then over the longer term, price signals from financial rights, price signals from the grid, we see it in a couple of ways, through taking the locational marginal prices over the longer term, the difference between any two locational marginal prices is the value of transmission or through the auction clearing prices themselves, which would also give you the value of an upgrade to the transmission grid.

Actually, those prices give you an indication of where it's valuable to upgrade the grid. And then market participants who want to take advantage of these market signals can do so and in return get the rights for having done an upgrade that created more capability. And I think this is how the Commission can begin to encourage, then, investment in transmission where it's needed on the power system.

MR. COXE: Thank you. My name is Raymond Cox, and I'm senior vice president of transmission marketing for TransEnergie U.S., and as someone who has sold a lot of transmission rights on merchant projects, my company has a great interest in how they're structured and how

they operate within a market.

In general, our view is that the direction FERC is taking and the FERC Staff in the FERC Staff paper is the right one. I would echo the sentiment that, where possible, transmission rights should be point-to-point financial. There may be occasions for inter-RTO or transfers across an RTO boundary where physical rights are more appropriate. For example, if the RTOs have somewhat structurally different organizations for LMP calculations.

So there are some instances where I think the rights become physical, but in general, our view is that financial rights are -- maximize the capacity that can be offered to the grid, grid users without impairing in any sense the ability to finance expansions of the grid.

I would like to touch on one other type of transmission right that I don't think has been necessarily very well discussed, and that's inextricably linked to the issue of installed capacity or whether or not there's a generating capacity market. To the extent that an ICAP or installed capacity market exists, it can't exist in isolation. A generator that is bottled in doesn't contribute to reliability, and I think there needs to be a recognition in any market with ICAP of the deliverability of the generation within that region.

And I think that also means that the

transmission that enables that generation to be delivered needs to be recognized for the service it's providing through what I'll call a "deliverability right" that would allow generation that may otherwise not be qualified as a reliability resource to become so qualified.

An example might be in the case of generation in, for instance, my area of New England in the Maine region which may not be deliverable and able to contribute to reliability within the New England market should probably not be qualified as ICAP unless and until more transmission deliverability has been put into place and, of course, put into place either through investments developed -- or transmission expansions developed through the RTO planning process or through a merchant investment, whereupon some of those generators may choose to fund some or all of the costs of an upgrade in order to obtain those deliverability rights.

This concept, then, also allows ICAP to be sold across RTOs. If you have a resource that allows for reliability in one region, say PJM, and you have adequate transmission path or rights, if you will, to reliably move that product to another region, either the Midwest or New York, that allows trade in ICAP as well as energy.

So I think with those constructs, transmission can be a stand-alone business, and the conductor we're

putting into ground already, I think, demonstrates that.

Thank you.

MR. THILLY: My name is Roy Thilly. I'm from the Wisconsin Public Power, Inc. system. We approach these issues from the perspective of a load-serving entity. My utility serves 36 cities that have their own distribution systems. We have a long-term all-requirements obligation to serve and those cities have an obligation to serve their customers in a state that is not likely to go to retail competition in the foreseeable future.

What our customers want is they want to take reliability for granted. They want prices low, but most importantly they want prices stable, and that requires a diverse portfolio of resources, both long and short term, and clear transmission rights that can be matched to those resources that provide stable delivered cost.

I would urge the Commission in structuring -- coming up with standardized market structure, which we do support, to keep it simple. Lots of complexity may benefit very large players and traders who can exploit the differences and arbitrage the differences in complexity, but provide very little net gain for customers.

The system design should focus competition like a laser on the costs of generation, fixed and variable

costs of generation, and to do that we need a robust transmission system. It's important to manage congestion, but it's even more important to get the system built so we don't have much congestion to manage.

From our perspective, we support financial transmission rights, as discussed in the MISO. We need those rights to be sourced to sink generation to load. They need to include system purchases that are aggregated load and not just purchases from a specific generator, and the allocation of transmission rights at day 1 is very, very important to existing resources.

Public power systems that have an obligation to serve their customers on a long-term basis, as well as utilities and states that have not moved to retail competition need to be sure that they will have the ability to deliver the existing resources which have been built for those customers and paid for by those customers to them on a reliable and economic basis. Otherwise, they're very unlikely to participate if they have any choice at all. And I think states are likely to take the very same position.

Those existing transmission rights have been procured with blood, sweat and tears. And I can give you an example. Our first resource is a coal-fired plant in northern Minnesota, distant from our load. When we went

to purchase the interest of that plant in 1989, we were told the transmission across a Minnesota utility would be \$150 a KW a year. We were also told that the price would rise each year to reflect the marginal cost of each addition to the system for 30 years.

We thought about that and turned it down and went to financing, made a notice of antitrust suit, and we finally got an agreement that the utility would file a transmission rate here for us and accept what the Commission decided. Previous to that time, we were told we had to sign away our rights to intervene, and that if any -- if the Commission changed the rate and lowered it, the transmission would go away because it was voluntary.

So on the day of the financing, we finally got them to capitulate on that. The rate was filed here. It was filed at \$44 a kilowatt a year, which included a bar cost that was higher than the cost of the fixed cost of transmission.

We litigated that. We ended up at \$14.77 three years later. We had to agree to take that service for 30 years or the life of the unit and to pay for it whether the unit existed or not. If the unit blew up, it doesn't matter. We're obligated to pay for it for 30 years.

Having fought that battle to secure that resource, the concept of it being auctioned, the

transmission capacity being auctioned to somebody else at this point is simply unacceptable. We need to be able to deliver our resources to our loads.

We also need to be able to convert our network service to financial transmission rights, to deliver the other resources that are now qualified as network resources. In terms of new resources, this is a significant challenge, to get new resources in place to meet load growth, particularly with the changes in the market and various power plants being canceled.

In order to finance and build new generation, which we think we'll have to do, we need to secure long-term matching transmission rights so that we can be secure in the delivered cost. If we can't do that, we have a congestion system that doesn't allow that, we're going to be forced to deal only with the neighboring or the local IOU. We will not have choice.

Backing up for a second to construction, the large market with RTO, with license plate pricing and hubs is very attractive, but it's really attractive in an academic sense today. We don't have any available transmission capacity into the state from the South or from the West, and we're now finding no available firm transmission capacity within Wisconsin between control areas. I can't deliver between -- get new firm

transmission between control areas within the state for this summer.

So an RTO has to not just manage congestion. We have an RTO with an obligation to build, to meet load growth, and to lead constraints. We need a system with performance-based rates that incent relieving constraints, and I think we need to spread the cost of that construction across the system, because all customers will benefit from a robust transmission system. Thank you.

MR. DOYING: Good afternoon. I'm Richard Doying with the PG&E National Energy Group. We're based here locally in Bethesda. Thank you for allowing us to come here and address this problem.

I want to address first the issue of the appropriate number and type of financial rights that should be offered, and I want to stress we're talking only about financial rights. I think there are very rare instances where transmission rights need to have physical attributes for transmission between RTOs, maybe some existing contracts that are grandfathered. But I think that will be a very rare exception and that from a market design perspective, we're really concentrating on the financial transmission rights used as hedging instruments.

The Staff has identified four possibilities for those rights. They were mentioned just a little bit

earlier today. We've got point-to-point rights, flow gate rights, and they can be offered as either options or obligations.

I'd like to argue that all four should be included in the standard market design, and moreover that RTOs need to be required to have an open architecture to accommodate changing the number and type of instruments and the characteristics of those instruments over time to add, subtract, or modify those hedging instruments to meet the evolving needs of the market.

I think it's critical to remember that transmission rights are financial, or when defined as financial rights are only hedging instruments. They really have no other meaning in the market other than to hedge financial risk in the market, and they're intended to facilitate trading in an underlying commodity, here the energy commodity.

As we talked about earlier today, it's critical to set up that commodity market so that it reflects the physical realities of the system so that you don't get any disconnects between the operations of the transmission system and the prices that energy clears at. We also need to have, then, a very good linkage between the prices in the energy market and the prices that these hedging instruments or financial transmission contracts clear at.

but beyond that, I think there's very little need to standardize or specify over time exactly what those instruments look like.

I think it would be a mistake to impede the development of the market going forward by arbitrarily limiting the type or number of transmission rights that are offered. With that said, to avoid implementation delays, I think we do need to have some standardization to get RTOs up and running quickly. We've already had too long a delay in RTO implementation, and our first priority has to be to establish competitive markets across the country.

And so to facilitate that, I think the standard market design should include those rights we already know how to offer today, point-to-point rights, obligations, and options. I think we do know how to do that today. Antioch was here last week telling us he was ready to launch a test auction of both financial point-to-point obligations and options.

I think there are other software vendors, based upon my understanding of the discussions between the Midwest ISO and vendors, that say they are prepared to offer that software today. I think there's no reason not to implement that immediately. It may be that that requires a phase-in of the existing ISOs from the markets

that they operate today based upon point-to-point obligations, to offering point-to-point options, and then adding in flow gates as that becomes technically feasible.

But since we are talking about a financial market, I think it's important that we acknowledge that since it is there to foster trade in the commodity, it's there for the benefit of market participants. We need to let the market participants and the market decide what those financial transmission hedging instruments look like.

We can specify something at the outset. But I think it would be a mistake to think about this effort as an effort to build a machine, and that once we have the pieces put together just right, we can let it go, and it will continue on and there won't be any problems. It's an evolving -- it's more like an organic mechanism that we're trying to build, and we need to let it evolve over time.

There are some other considerations that will affect the success for the market for effective transmission rights that weren't necessarily addressed in the Staff white paper, but that I think are important to consider. First is that the hedging instrument should be fully funded. That's not the case in all the existing ISOs. I think that's a very important requirement going forward. It not only requires better hedging tools for

market participants, but will enhance liquidity.

Second, the rights must be auctioned instead of allocated. I think we need to acknowledge that the revenue from the auction needs to be allocated to those who pay for the transmission, but I think we also need to recognize that the energy is going to flow from the resources today to the ultimate load in the future. And we don't need to set up a system that tries to mirror the physical rights system that we have today and handout those rights.

If we want to have a liquid competitive market, we're going to need to auction the rights, let the market determine the value, and send the revenue back to current load rather than the actual transmission rights.

Third, we need to work out a mechanism to grandfather existing rights. I think that's going to be complicated. I don't think we know the answer yet to what will work best in that process.

It may be to grandfather existing rights as physical rights with some sort of provision for release so that we're sure that those are available to the market in real-time. It may be that we decide that we would like to turn those into financial rights immediately.

There are going to be trade-offs there, and people that have existing grandfathered contracts are

going to lose something in the process as they're grandfathered. We can't not grandfather them, but there are going to be trade-offs there, and we're going to have to work those out as we go forward.

Lastly and, perhaps, most importantly, we need to ensure that the government structures of the RTOs are responsive to customers. This notion that we can set up a market and let it evolve only works to the extent that the people who are operating the market, the people who are deciding what instruments to offer to the market are actually listening to the customers, responding to the customers' need, and allowing the market to evolve in ways that help them.

Thank you.

MR. SCHNITZER: I'm Michael Schnitzer with the NorthBridge Group, a consulting firm. The usual disclaimers, the views I'm going to express here are at most my own, and I appreciate the opportunity to be here.

Generally speaking, I support the position outlined by the Staff in the white paper on transmission rights, that they be financial rights settled against actual congestion. I think the general proposition of financial rights is rights settled against actual congestion. Support for that premise, if you will, is not independent of everything else.

As someone observed this morning -- I think it was John Meyer -- that this is an integrated package of standard market design elements that we're trying to put together. So when I say I'm for financial rights, I support financial rights for transmission, that's in the context of bid-based security constrained LMP markets on both a day ahead and real-time basis that are carried through on a nodal basis.

I think financial transmission rights, as the Staff paper described, makes sense in that kind of a context and not so much otherwise. The FTR is obviously an element to that standardized design, and an ICAP market of some sort may have been some deliverability, some occasions for transmission, different kind of property rights there. Those are at least some of the elements of SND, and financial transmission rights make sense in that context.

These financial transmission rights are, of course, very important in that market, because they are the means by which users can hedge the congestion costs of their transactions, which is pretty important. And I think there's been a lot of focus on that, but there's another equally important benefit that I want to take a minute to talk about, and it has to do with expansion.

When we have FTRs in the context of the

standard market design, we create a new option for dealing with transmission expansion and for pricing transmission expansion, because essentially we have defined a set of property rights that we never had before, which are these FTRs or whatever we're going to call them. Just as we have to decide and determine what the FTRs are for the existing systems, the allocation problem that other speakers have been talking about, so, too, when we add something to the grid we have to measure the new FTRs that have been created.

If we have to do that and we can do that, that property right becomes associated with the new investment. That gives us an alternative to the traditional rolled-in investment, rolled-in investment treatment where we make the investment, roll it in, and raise everybody's transmission rates a little bit.

If we do go the rolled-in route, we undercut some of the benefits of LMP in terms of new generation location. We undercut the price signals that we're sending, because price differentials can be remedied by transmission investment that someone else will pay for. That's particularly damaging to distributed generation and the demand-side contributions that may exist for those problems.

I think rolled in is not the best way to go for

competitive generation market. We also miss an opportunity to let market participants decide when a transmission expansion is economic and when it is not. After all, a transmission expansion is a bet against the future market prices at a couple of different places on the grid. That's hard to know with certainty.

It's the type of decision that we're willing to let generators make in the first instance, and it's not at all clear to me why we can't let market participants make those decisions with respect to transmission as well. So I think the preferred grid expansion policy is one similar to what the Commission does for natural gas pipeline expansion, where we have market participant funded expansions in return for the property rights that are created. This, in my judgment, should be an additional element of the standard market design, that expansions which expand the grid should be market participant funded and not rolled in.

I'd be happy to talk about any of these topics further. Thank you.

MR. NAUMANN: Thank you. I'm Steve Naumann from Commonwealth Edison, one of three of the Exelon public utilities, and I'm here on behalf of Commonwealth Edison, COPECO Energy, and Exelon Generation, which includes Exelon Power Team.

A lot of what I wanted to say has been said, but it's been said two ways. So let me try to make a couple of quick points.

I agree absolutely with what Michael just said. Extended market design is something you take as a whole. It's not a matter of going to a restaurant and ordering an appetizer from this list and an entree from this list and a dessert from this list and having a wine, whether it's the right wine or not. All these pieces have to work together to get an effective market.

And so Exelon supports the type of market that was discussed this morning, discussed in the Staff paper, two-settlement system, security constraint, dispatch with the day-ahead and the real-time market. And again, the transmission rights that we're talking about here work within that. The market design also has to be standard.

Many of us went through this issue in Order Number 888, should there be regional differences. I think we've seen some of the down sides of regional differences, but when we come to market design, we really have to make this standard, even to the point -- and I'm sure it's been mentioned several times. New York has an LMP system. PJM has an LMP system. There are issues involved in transacting between them. We need to deal with that.

A small point, we're throwing a lot of terms

around, and they're not all terms of art. I think we need to have these terms used defined. I've seen the term "flow gate" change its meaning three or four or five times in the past year and a half. I'm not dumping on flow gates. It's just an example as to what these terms actually mean when they're used so that we're speaking on the same page.

As far as the rights, Exelon supports the point-to-point financial hedges. We know this works in PJM as obligations. We need a system where you do not need an FTR in order to be able to flow. I know today we're going to talk about options versus obligations, flow gates, et cetera.

I think the Commission needs to take a look and say, what do we have working now that we know that works? Do these other additions which are granted have benefit to a market design? What is it going to take to get the software development -- and software development is always an iffy issue in terms of both time and money, and will these work, and what's the risk here in terms of time and cost and balance that go against the objective of getting markets up and operating in the RTO quickly.

I think the bottom line is we have a system that works in PJM. Granted, there may need to be a few modifications. We need to go and get this done. We

touched on the distribution of rights, the initial distribution of rights. We support what Roy Thilly said for many of the same reasons that Roy brought them up. We would say all existing firm uses, both point to point and network, should receive an initial allocation for at least a reasonable transition period of time.

It recognizes that these are the customers that contributed to the support of the transmission system. They've made long-term obligations in many cases in terms of their resources, as Roy described in great detail in his case. I'm sure not everyone has to go through all the machinations Roy has, but we've all made these investments for the customers.

The issue in retail access in states Exelon operates in can be taken care of within a system of releases, and you do have to deal with that. No one's saying give the -- allocate the rights to the existing firm users and, you know, hang on to them and you stifle retail competition. You need to deal with it, and there are rational ways to deal with it to be able to do it. And then initially, auction anything remaining. No question about it, they should be auctioned.

Two more comments. On the model itself, I think the Commission needs to undertake a presumption, and the presumption is that whatever the standard market

design is that's promulgated, any changes that are proposed to that model, whether it's in the development phase or afterwards, need to be shown first that they work, but besides that, that they are better than what you have, not just that it's an alternative that's just as good, because why change it. Again, this goes back to what needs to be standard. Changes need to be better than, and that should be a high standard. I've got some thoughts about how to do that.

The last issue is timing. I've mentioned earlier, we really need to get the markets up and running. Exelon supports the Commission effort to try to get a final ruling out by this summer.

Last October, when I spoke on one of these panels, I went back to a book I read a number of years ago, the "Soul of the New Machine," about the mini-computer where I heard the term "get it out the door." I still support get this out the door by this summer, if you can, and don't let the perfect be the enemy of the good. We need to get competitive markets up and running.

Thank you very much.

MR. MARONE: Good afternoon. My name is Joe Marone, and I'm here today on behalf of Occidental Corporation.

The success of any standard wholesale market design is how well it supports a vibrant retail market. The vibrant retail market requires a robust transmission system. Chronic congestion is not a characteristic of a robust transmission system, and therefore, it is a threat to the viability of the retail market. LMP models and market signals induce investment to relieve congestion, but this signal is a Catch-22. Any investment undertaken to capture the congestion premium embedded in the LMP price by the very process relieved in the congestion causes the problem to evaporate.

Congestion causes potential retail market issues in the allocation of transmission rates. Any process that allocates transmission rights to incumbents runs the risk of creating a barrier in the retail market. Transmission rights should be assigned to the load to facilitate the switching of suppliers.

The play of the electronic cooperatives located in the southern DelMar peninsula serve as an illustration. They are both transmission and generation dependent, just like a retail customer. One, for example, is approximately 400 megawatts of load and allocation of 100 megawatts of FTRs. They've been exposed to as many as 4000 hours of congestion pricing per year, but their retail customer rates are frozen. LMP pricing and FTRs

provided neither a solution nor sufficient protection from the harmful financial impact of chronic congestion.

The preferred standard market design should define congestion as a reliability threat to the health of the retail market, and as such, its remedies should be afforded all the same considerations given to physical reliability issues. Fair demand response programs should be implemented and used as a potential lower cost alternative to generation redispatch. We not only need ways to manage congestion, but ways to fix it.

MS. FERNANDEZ: Thank you. A number of you mentioned allocation versus auction, and I'd also like to touch on the last point Mr. Marone made. One, for a lot of the load, you said you would prefer allocation versus auction. Ms. Manz said another option is you might do auctions of the rights, but then you would allocate the revenues to the load.

I guess I'd like to understand why you think you need to allocate the hedging rights as opposed to an allocation of the auction revenues, why you think one would offer much better protection. And I think another issue is sort of from -- I also heard from a number of the people who, I think, don't currently have rights, but would like to get them, a concern that allocating to just existing incumbents may discourage the release of those

rights, that in the methodology that's used, how do you set up a system that encourages the holders of those rights to release them to people who do value them the most.

MS. MANZ: I can jump in. I think it's very important under any scenario that there has to be an allocation mechanism back to those who paid for the transmission grid. So there are a couple of questions that go along with that, then. The first is -- and we have an allocation mechanism currently within PJM.

So let me paint where we are and why we went there. We didn't know how an auction mechanism would work. Being first out of the gate with LMP, we wanted to try something that we thought might work.

So we went to an allocation mechanism. Then we went to retail choice. So the allocation mechanism itself works with retail choice, and it's based on the amount of firm network service that any load-serving entity buys, and it's reallocated all the time. So you can do the allocation in a retail choice world.

What you don't have when you do it that way is any idea what the rights themselves are worth. And so what we know in one sense is because no one has stepped up to the plate with an offer price to someone who holds a right that's high enough for them to want to sell the

right, because these things can already bilaterally trade.

And so you'd have to somehow assume that those who are offering prices to buy the rights aren't offering a high enough price for someone to be interested, but because this isn't done through a central auction mechanism, what's lacking is the price transparency.

And so you have, first of all, no way of knowing what the value is, because it's done in a private set of transactions, and there's nowhere to post the value should you even find somebody who achieved the value through offering a purchase price.

Have I covered all your questions? The existing incumbents, that's kind of an interesting question, because you go from sort of the old-style, absent retail choice to the new style. We have to remember it's the retail customers actually paying for the system. And so whoever is their load-serving entity, whoever is their transmission customer is at that point the incumbent. So it changes a little bit.

MR. MARONE: I think there needs to be an easy system for that right to transfer. You can't have somebody come in and try to pick up retail load and have this barrier of having to go to another entity to get the transmission. That's why I say the right ought to tag with the load so if you get the load you automatically get

the right, so it's not a barrier to entry.

MS. MANZ: I think there's a really important point in what you say in the simplicity, and that has to go to the price of nodal pricing. Once you have nodal pricing you actually in theory have rights that go to every single node on the system, but then you can recombine them. You can actually have point-to-point rights that go from a trading hub to a trading hub, or you can have point-to-point rights that go to what I would call a settlement hub.

So the way we use these is that the right itself goes to, in our case, all 200 nodes are defined as a single point. So you do only have to choose from your source, your generation source, to the single point which is the delivery zone. It's that collapsability, if you will, that allows these points to be traded pretty easily. I agree with your point on simplification.

MR. NAUMANN: Inherent in what many of us are saying is we agree with Joe, that the rights belong to the load or its load-serving entity. As I said, there needs to come within the system the requirement to release and probably to reconfigure those rights periodically to account for retail access.

So that the load again historically had paid for the transmission system is now able to get the

congestion hedges that they had before the incumbent's utility and to go with the new supplier so retail access is not stifled. I think that is a basic piece.

Now, the other question is, why would you want the rights themselves rather than the revenue? And I think one of the reasons is you can get into, with the interaction between the federal and the state jurisdictions, you could get into a position, for example, as a transmission owner who is a load-serving entity, that you're required to take those revenues, credit it against your network service, reduce your transmission revenue, and have no income for your transmission hedging that you're required to have. So you would be worse off, in fact, even though you have to do the hedging.

I think you have to understand that in many states, you have de jure rate freezes. So the congestion costs would be on the load-serving entities for the duration of the rate freezes. I suspect in most other states you have de facto rate freezes, but that's a different matter. So there are legitimate reasons why you would want these rights, again at least for some reasonable transition period.

I'd also to explain why I say transition period. Roy has explained very eloquently his need to hold the delivered cost. If you look at the situation we

have today under the pro forma test, one of the things that when a new network resource or a new network load comes in, the Commission has said that you are not required to increase congestion costs to accept a new network load or network resource. You have to build to do so, because the existing network loads would suffer a pro rata share of increased congestion costs, and that wouldn't be fair.

I think that's what we're saying here, that in a transition from one regime to another, the people who paid for the system and who have made investments, both in the transmission through their rates and in generation, need to be able to go through a transition to rationalize those costs and avoid the cost-shifting, at least for some reasonable period of time.

MR. MEAD: Can I ask sort of a follow-up question? I'm having a little difficulty understanding why ultimately, in terms of who ultimately ends up with the transmission rights, it makes any difference whether there's direct allocation or an auction, especially if you presume that in an auction the current holders of the transmission rights would be allowed to bid for them as well.

And if that's so, is there any reason to suspect that the amount that the current holder of a

transmission right would be willing to bid less in the auction than the price that, you think, a nonincumbent would need to offer that entity in order to have that entity give up their rights in the first place?

MR. SCHNITZER: I think that question is right on in trying to clarify whether there's a difference here. If the allocation of auction revenues is going to be the same as the allocation of what otherwise would have been an allocation of rights, in other words, if Roy knows that he's going to in the one world get rights to move power from the coal plant in Minnesota into Wisconsin or in the other case he was going to get the auction revenues from the sale of that rights, and if he knew that in advance, if that was true and he knew that in advance and he could bid in the auction up to an infinite amount to make sure that he won, if you will, then I think there's less difference.

But the concerns about auction versus allocation are not as precise as we need to be about are the auction revenue allocators and the auction revenue allocation rules the same kind of rules that we would actually use to allocate the rights. Do the people know in advance what they're going to be allocated, and are they allowed to bid without a cap? If we walk all the way through those points and we get them resolved, there may

be less difference here.

That being said, the nonincumbents may be no more happy with the results, which is the second question about liquidity and about the incumbent. If it turns out these rights vest in the load-serving entities and the load-serving entities for reasons they think they're very valuable or for reasons having to do with retail rate design, if they're going to put a very high price on those implicitly in the case of holding on to them or explicitly in the case of bidding unlimited in an auction, the nonincumbent market participants will be no happier with the results.

We can go down that branch, but it's not a panacea to where people, nonincumbents are able to get rights at a price they think is affordable. Auction versus allocation doesn't get to that.

MR. THILLY: I think what was just said was correct. It is safer from our perspective to have the financial transmission right than the auction when we have no experience with the auction. We don't know how the auctions are going to work or how, you know, precisely. So I think that moving to the auction is probably a stage 2.

MR. WALTON: I'd like to second that. In terms that the auction rights -- the auction revenues and the

rights, theoretically they all come out of the same price, everybody's happy. The difficulty is when you start these new systems, there's no track record. There's no history of congestion costs. They're all buried in the systems. No one knows what they are. We've tried to estimate them. We don't know what they are.

Having had some experience in another position where we tried to bid in the New York auction and we only had six months of experience and we were trying to price two years out, there was a good deal of swagging going on in order to figure out what those prices are. It was really difficult. It's, I think, asking an awful lot and is cold comfort to say well the auction numbers are the same. No one knows if the auction revenues and cost of congestion even look like each other when you're just getting started. It's very difficult. I don't think -- I know that our customers are not willing to do that.

Now, having said that, there is a need, having allocated those rights, to have an incentive for them to release them as much as possible, and the design that we've come up with, which is to pool all the grandfathered rights, in effect they become financial initially, but they're pooled so that most of the releases can be maximized and also to give them positive incentives.

That is, the only way they can get the value

that right is to, in fact, release it to get the full value and by triggering the formation of the secondary market, then we hope to achieve the liquidity we want in these rights. So the problem on a start-up is that no one knows going forward what that auction and the actuals, because no one has a track record.

MR. DOYING: If I could jump in here, I think Mike's clarification was very good that, we need to think about this as an entire system where you do have an auction. The revenue from the auction is allocated to the people who are serving loads today. And let's just for a moment assume that we could make that happen and that you could write standard market design rules and Roy could be comfortable from the outset that he'd be taken care of.

If we make all those heroic assumptions -- maybe they're not so heroic -- then I think we can look at the best practices and the RTOs that have prior experience in this area. We've gone through the allocation route in PJM, as was mentioned, and the representative of PJM told us last week if he had to do it over again he would auction them.

In the case of New York, they didn't auction immediately, and I think there are concerns whether the prices you got initially in the auction are the result of sort of a reasoned, rational economic system. New York

addressed that problem by auctioning them in very short time periods. So you have a monthly auction. The next month you have another monthly auction, and as people gain experience in the market, you can keep extending that time period until you get out to longer and longer term rights.

I'm not sure the fact that we don't know today what prices that market might clear at should make us shy away from moving quickly to that market. I think it's important to remember the context here is that we're trying to establish competitive markets as contemplated in Order 888 and Order 2000. And to do that, I think we need to move pretty quickly to mechanisms that are likely to foster those kinds of competitive outcomes we were looking for.

We were looking for an efficient allocation based on market prices, based on signals that were transparent, liquid markets. We definitely will not get there if we do an allocation of rights. We're much more likely to get there if we do an allocation of the revenues to the rights. And going to Mike's point that it's not a panacea, it's not a panacea if someone chooses to bid an infinite amount to ensure they get the rights they need. That's okay. Those are removed from the market.

But I think the experience in New York is that people in general don't do that. Some people will bid

very high to ensure they get the rights they want. Other people will look at the situation. They'll evaluate. They'll try and figure out what the right price to bid for the rights is, and the auction worked reasonably well.

MR. SMITH: I would just second Richard's comments, and I think, you know, to the issue of not knowing ahead of time what the congestion costs are, I think even in a market like PJM, even on a short-term market, sometimes if you look at the auction clearing prices versus the actual congestion, you're not always close, even when you have that.

So you have to start somewhere, and I think an initial auction is the only way we're going to get there. At least at that point everybody's going to be forced to look at their cards and decide if they're willing to accept the auction revenues at that point or whether they're going to bid higher. If we never get to that point, we're never going to gain that experience.

MR. WALTON: On the other hand, you've got a situation where you've got contracts you've signed. Some of them are long-term contracts with parties who are not going to be a part of the RTO. They are public utilities and others who have signed contracts, like Roy's customers, they feel they've fought long and hard to get these rights. They're not about to surrender them. They

do not want to have those taken away from them. We can't compel them to turn over their contracts.

Bonneville, in particular, is committed to go forward with offering those contracts. And the only way to get that done and still meet the product -- or the intention of the market, to put the real-time and the day ahead and all the other features in place has been to provide for a system which honored those contracts.

Now, we've done that in effect, but by an allocation or a cataloging of the rights. You have to do that in order to honor all those contracts. The contracts between the utilities, the Commission has jurisdiction over, but between bone fill and its customers, I don't believe they do.

MR. MEAD: Can I just follow up on this? What I've heard a variety of people say is that -- well, let me just back up. Suppose one of our objectives is to have an allocation of transmission rights that puts those rights in the hands of the folks that want it the most.

Of course, there are other objectives like fairness and proper allocation of revenues and all that sort of thing, but in terms of the objective of allocating transmission rights to those that value them the most, we have two systems on the table. One is the direct allocation, in which case if there's somebody else out

there who thinks that they value those rights more, they will offer a price, and the issue is do they offer a price high enough to lure the incumbent holder to give them up. And then there's the auction where both sets of parties are submitting bids.

And what I've heard suggested is that the incumbent transmission rights holders might bid less in an auction than the price that they would be willing to pay -- to receive to give them up voluntarily in a direct allocation sort of system. If that's so, how do we decide -- which system is going to better result in an allocation of rights to those who ultimately value them the most?

MR. SCHNITZER: I don't personally believe that would be so. Others can speak for themselves, but the proponents of auction are not motivated, I think, by the belief that people will bid less in an auction than in taking a bilateral transaction.

I think there may be transaction costs and information differences, but I think also people are just looking for some visibility, some price visibility that that particular FTR cleared at, you know, \$3 million last month, and was that a good thing or a bad thing for you to have held on to it. But I don't believe it's a belief that someone's going to bid a different price at an

auction than they would have accepted on a bilateral basis, at least initially.

MR. NAUMANN: I think this comes down to one of the points Michael made earlier that is very important, and that is in an auction, how are you going to allocate the revenues from those auctions? If you're going to take all the revenues from the auctions and pool them and somehow distribute them back to the load-serving entities, then you don't necessarily get a one-for-one of the value for that right.

For example, knowing a little bit about the Midwest system, the rights across the Minnesota-Wisconsin interface are extremely important to those load-serving entities. If they don't get the direct allocation of those rights, then they're worse off. If you get a direct allocation of those rights, as Michael said, since you're going to get the money that you bid, nothing really has changed.

The fact is if you go to an initial allocation based on existing -- again, I still think for a transition period, but if you do go to an initial allocation and then somebody comes to you and says you know what, I'm willing to pay you X for this right, you now as a holder can make a decision. Is it worth -- what do I now think the congestion's going to be versus what I'm being offered.

And you can do that in the secondary market, because again, one of the premises we've talked about is do you not need a right to flow. So now it's a matter of a judgment.

I agree with Steve Walton. You may not have a benchmark, but, you know, for an active interface, people are going to offer money for those rights if they think it's valuable, and people will make judgments. By the way, some of those people will end up better off, and some of them will end up worse off because they sold their FTRs and congestion turned out to be worse, and that's what the free market's about, making those decisions.

MR. SCHNITZER: One other point, because Steve has mentioned this a couple times now, first in his opening and then a few minutes ago. Of the two methods on the table to encourage liquidity, one being the auction and the second being this use-it-or-lose-it characterization that he described, which I appreciate it is it after the fact the value of your FTR turns out to be bigger than your congestion bill, your congestion bill is zero, but doesn't go negative.

As between those two choices, I think the auction is sounder than the use-it-or-lose-it. If you're bound and determined to go one way or the other, I would say go toward the auction rather than the

use-it-or-lose-it. I think the use-it-or-lose-it characteristics which make these rights look a little more like physical where you have to forecast what your actual congestion is going to be, figure out what your rights are and whether you're going to be surplus or not is a set of calculations that one of the benefits of a pure financial rights is that they're totally divorced from the dispatch and all the rest. You don't have to do that math.

So my own view is that that would be the last choice of policy tools, to encourage trading or liquidity would be the use-it-or-lose-it type of characteristic.

MR. THILLY: I think the point about the allocation of the revenues, I think to be clear on is where there's a lot of nervousness on our side. The map 1 interface may have 700 megawatts of firm transmission rights. I have 107-megawatt commitment across that interface, which I had to go agree to pay for for 30 years, come hell or high water.

Am I going to get my load ratio share of that allocation, or am I going to get 107 share megawatt? It makes a big difference. I know of no retail customer who has had to make that kind of commitment.

MS. MANZ: I think you have to solve the allocation problem in any event. I don't think you get to duck under that one. And so if you work on the issues

such as Roy has set up to say how is my allocation going to work, that's the first problem you have to solve in any event. And then you have a question of speed and visibility, because I think ultimately you're going to get to the same market point. And if I hold my rights and I can trade them bilaterally, ultimately over time I may get to the same point where I clear them through an auction.

But what you trade off in that case, if you don't have a way to facilitate the trading is you're going to be trading bilaterally until you come up with a way that you can get the speed through an auction mechanism.

MR. MEAD: In terms of transparency and visibility, it would seem to me that the auction method has more transparency and visibility than the bilateral -- or the direct allocation. If I recall correctly, in your opening statement, you were favoring direct allocation rather than auctioning.

MS. MANZ: I favor direct allocation of the rights for those who have invested in the grid. That allocation happens whether you trade them bilaterally or whether you cleared them through an auction. So that was my point, was that whoever has paid for the transmission grid needs an allocation, either of the auction rights or of the allocation of the transmission rights themselves. Sorry if I confused you with that.

MR. SMITH: One other point on that, Dave, I think you do make an important point, from my view, whether or not an incumbent may be willing to pay less in an auction than they would transacting bilaterally, you know, who knows whether that's the case or not. But at least if you auction the rights initially, everyone's going to have to make a conscious decision whether or not they want to pay the price or take a lesser amount.

I mean, it forces everyone's hand. You have to make a decision. You're not trying to go bilaterally, find the right party, and all you hear is no interest. That's too easy. But if you are required to auction the rights, you have to make the conscious decision, and there is more price transparency and visibility in the market. If we're going to get liquidity in these markets, I think that's the best way to start.

MR. WALTON: However, if you have an auction right off the reel, you're asking customers to expose themselves to substantial price risk they haven't had in the past. In the case of someone who controls their rights, they know they have control over their transmission costs, they have the ability to schedule and move electricity as they have in the past.

If you go forward and suddenly compel them now to give that up and take this allocation of revenues and

say that will be okay, everything works out fine, that is not acceptable. We have had two years of debate over this issue, and it's the easiest way to break up an RTO West meeting is to bring this issue up again. It's a guaranteed killer.

So what we're telling you is that at the point of initially or at the outset here, in order to honor these contracts, they have got to be allocated. That's just the way -- that's the reality of where these folks are at. And it would be better, it seems to me, rather than compel them to take this risk to create the system where they have the opportunity to take the risk for the reward rather than being compelled to give up what I think they've won by hard, long bargain and argument over many, many years to give up those rights at the outset.

COMMISSIONER MASSEY: Are you and Laura in agreement?

MR. WALTON: No, she's saying the auction revenues are adequate, and I'm saying the auction revenues don't cut it, I think.

MS. MANZ: I'm saying that in an auction -- and I think we've talked about this already, and Mike, please jump in, because I think this was your point, was that someone who holds an allocated right, because that's how you get them in the first place, should have the choice to

put in a bid price below which they don't wish to sell it.

MR. SCHNITZER: If you're going to go with an auction, it should have three characteristics, an upfront allocation of the auction revenues that would mirror the rights that people otherwise would have gotten. That's number 1. Laura said that a few minutes ago. You can't duck the allocation price. It's sort of point-to-point specific. You're going to get 100 of these, 107 of these, I guess in your case, Roy, 107 of those across Minnesota. Number 2, you have to tell them in advance.

MR. O'NEILL: Roy, is your right an option right? It's not an obligation right? It doesn't turn on you, so to speak.

And I assume Steve, the rights you're talking about are option rights?

MR. WALTON: Right.

MR. O'NEILL: I think Laura and Mike are talking about obligation rights.

MS. MANZ: Dick, I'm not sure there's a difference, except for what they might clear for.

MR. O'NEILL: My point is that we -- that actually is going to segue into my question. I know how to calculate auction rights for a linear DC. When you change that to an AC, it becomes a much harder problem. And as far as I can tell, the literature hasn't solved

that problem and there's a bunch of software guys running around trying to calculate algorithms.

I can also take flow gate rights, and if I know enough about the system, I can probably construct an auction right that looks something like I would reasonably want to hedge a transaction.

I heard people say that auction rights are easy, I think I heard people say that option rights are easy and option rights are hard. Is there something that I'm missing here? I think that option rights are hard. Maybe approximate option rights may not be terribly difficult, but trying to perfect option rights may be difficult.

MR. NAUMANN: At least what I was saying was we don't have them yet in a working system, and I think there's -- you're right. There are software developers who have said they're working on it. And many of us here have dealt with software development and know that it can take time, it can take money, and you may or may not get what you want. I'm sure these people get you what you want. The question is when.

So what kind of time risk is the Commission willing to take here on getting the initial market operating? I don't think, at least for Exelon, we're not saying never go to options, it's unworkable. What we're

saying is take the system that we know will work, get it out, get it implemented so we can start the markets, and then make the improvements incrementally. We would recommend through a committee of the RTOs so that before it came up anywhere -- and again, using the standard that I said, but it's a matter of timing.

We could sit here and be back two years from now and have the same discussion and probably would be better to be back here two years from now having a different discussion on some other issue. We don't know if they will work. Andy is optimistic. It's a moving target. I think we want to get away from moving targets that lock them down from the beginning.

MR. SCHNITZER: Even assuming they work, which is a fact not in evidence, but assuming they can be made to work, there's a higher hurdle than that. There's a potential conflict between options and this grandfathering and allocation problem we've been talking about, that if you could have just as many options as obligations, then this would be easy.

The people who thought about it say no, you're going to have fewer options than obligations. If it turns out that giving everybody enough grandfathered rights to keep them comfortable and keep them in the vote is hard already as obligations, it isn't going to be any easier as

options.

MR. O'NEILL: By the way, I think we're talking about grandfathering option rights.

MR. WALTON: What we've issued for the last 20-some years of my career have been options. We have never issued obligations.

MR. SCHNITZER: In the ITC, when you're granting an option, it's on top of a base flow, which is treated as an obligation. So when you look at the totality, not just the ITC on the margin transaction, but the base flows and everything else, there's a whole lot of obligations in there and it could turn out that there isn't a single transaction which sets an opposite sign with respect to the same flow gate, but I doubt it. That just means you're going to have fewer options and obligations.

MR. O'NEILL: We understand that. I think it's taken as a given that there are less option rights than there are obligation rights. That's easy. People want, you know, option rights. As a matter of fact, almost all of our other tariffs here are option right tariffs.

MR. SCHNITZER: I appreciate that. The two places where you've actually done this, New York and PJM -- I will let Laura speak to this, but my understanding is those allocation conversations were not

easy, quick as obligations. They were very difficult and very contentious. And I think they would have been even more difficult if they had to take place as option conversations. Those are the only two places where you've had to go through the full allocation of the rights.

MR. O'NEILL: It may not be that this is a day 1 type issue. The question is, you know, where should we take it. Is it a day 2 issue? How important is it? If it takes a lot of software development, you know, is it worth the effort? There are certainly -- I assume Roy and Steve would like to sort of keep the option rights on the table.

MS. MANZ: Dick, I want to jump in just for a moment here. When we solved the problem, the problem of LMP, the first issue we had to deal with was price certainty, and we designed these rights as obligations because the request was I want price certainty from my load to my generation. And so that's what you get with an obligation.

And we were also trying to deal with the issue of will there be enough of these to trade. So we made them obligations because there are more to be traded. That's why we feel that that's an appropriate starting point, and then above and beyond that, if you want to create more products, let's see how it goes to the degree

they're desirable, market participants want them.

Again, we're trading off one product for the other within the transfer capability of the system. And then you start trading options with obligations and how do you get these things to convert to each other so that they're tradable across the products, as well as across the grid.

You're right, it becomes a pretty hard problem, but I wanted to be very clear that the issue we dealt with, first of all, was price certainty from my load to my generation that, I've paid for the grid, I've paid for this deliverability, and that's what we did with obligations.

MR. THILLY: Dick, you're right, I would rather have an option than an obligation, but the obligation is what's most important ultimately, is the delivered price to the load. It seems to me very clear that at least as to new resources, that if you do options, you're going to further constrain the system, and that is definitely not in our interest.

But again, we come back to the real question of how do we get facilities built so that this argument is not half as important as it is today.

MR. WALTON: The only other issue here is that we seem to be saying oh, well, is it for the purposes of

standardization, you know. I know you don't want obligations, but we're going to give them to you anyway, and we're saying we wanted to be responsive to customers that are asking for options and say they can't have them. That doesn't make any sense to me.

There's a large amount of trade, energy trade, even between hydro operators, on a day-to-day basis, and these options are the way that they think about the world. It's what they want. It's what they want to be used, and it's useful to them and productive. So thus, they want to do it.

Number 2, as I recall the FTR manual from PJM, when you're allocated a set of FTRs, if there's some you think are going to turn negative on you, you can decline them. Yeah, you can turn them away. So this same sort of mentality is evident in other places. We want the options because that's the way we think we can optimize and operate this system.

MR. O'NEILL: I think the only issue here is whether -- how difficult it is to implement them and how fast you can get them implemented. Everybody wants option rights, and yes, they may actually not be as many, but if people are willing to pay for them and if you can offer them both simultaneously, I mean, it's not that you can do one or the other. People can make their choices, then it

would seem that more choices rather than less make more sense.

MS. MANZ: Dick, one other thing occurs to me as I'm sitting here and we're having this options versus obligations discussion is that we may need to look one more level into the debate and say are we really talking about the option or the obligation to take the right versus the right itself being an obligation or an option. So I'm not sure if I'm adding any clarity to the debate, but I'm hearing Steve say a little bit maybe we just want the option to take them if they go the wrong way.

MR. WALTON: No, we want them defined as options. We want the option to define them as options and not the obligation to issue only obligations.

MR. MEAD: Can I follow up on this question for a second? I understand and appreciate Dick's point that it's more difficult to determine how many option rights are feasible, but let's imagine some time in the future, hopefully in the near future the software people and the other experts can tell us what that number is.

Is there any reason why we wouldn't want to require the RTO to offer both, both options and obligations and let people bid for both, and whoever is willing to pay more for the particular rights would get them, and if that turned out to be options, that's great,

and it turns out to be obligations, that's great? Is there something wrong with that paradigm?

MR. WALTON: I don't think there's anything wrong with being able to offer both, and even in an option world that we've been talking about, there are particular values in someone taking the reverse position. But in order to take a reverse position, they need to do that. They need to be able to enter into an obligation to do that. So having both available is fine, but it doesn't prescribe the -- prescribe the situations that you must start with obligations and we'll let you think about options later.

MR. SCHNITZER: I don't have any problem with that either. I think the question is do you require that on day 1 or do you start what you can do, which is the point-to-point obligations and add the others, if and when. If you had to wait 24 months to where the experts could tell you that and it was debugged and all the rest, my own view would be it's not worth waiting.

Similarly, if someone told you it was \$80 million per RTO or \$300 million per RTO in computational stuff, you might reach a different decision. But if it didn't cost any money, didn't take any time, sure.

MR. MARONE: As a load entity, I would like to have the option of either, one to set my price so I have

price certainty, the other one to hedge congestion as an option. The concern that I have is liquidity and confidence in the market, because congestion's prone to maintenance scheduling outages, which means it can be manipulated, and since it can be manipulated, whether it is or isn't is a concern.

So I think you need to somehow tie -- if you're going to do an options market, you need to somehow tie maintenance outages into what its potential impact is on the options market.

MR. SMITH: I too would be supportive of having both options and obligations. There again, I would echo Michael's comments that, you know, the place to start is with obligations, and if options can be added at the same time, great. If we need to wait some period of time, then fine.

I think going back to Steve's issue, I think that the bigger problem is if we start allocating rights initially and they're all defined as options, I think we're going to have problems.

MS. FERNANDEZ: It looks like we're right about 3:00, which seems to be a good time for a 10-minute break, if we can get back at 3:10.

(Recess.)

MS. FERNANDEZ: Why don't we start and get into

a slightly different topic, and that's expansion costs, both in terms of merchant transmission lines as well as other expansions. And I guess sort of the basic question is -- that I'd like to ask the panel is, in terms of designing the standard market design, how should the market design be set up to sort of provide the appropriate incentives for construction when you do have the areas of load pockets, areas where there is continual congestion?

MR. COXE: Maybe I'll eagerly jump right in having been silent on this morning's discussion, which was sort of fascinating from my standpoint to observe it, but not because it was discussion about how rights and capabilities in the existing transmission grid should be allocated. But of course, the busy focus on is delivering new transmission capacity in response to the market's signals and incentives that we've talked about.

So we very much appreciate the chance to start looking at the future and how can the market be designed to expand the grid. I think many of the elements that are necessary to finance transmission expansion on a market basis are in place in -- particularly in the Northeast U.S., in terms of a transmission rights that I briefly touched on this morning.

And we've got a one-page template of what we would suggest available in the back and available here.

We can and we have built transmission projects in a variety of circumstances based on financial or physical rights. I'm here to say financial rights are adequate, if they're properly structured.

I think there are a few issues on financial rights we haven't touched on. One is that I think, for example, the right holder should have the option to settle out their financial transmission right, either at the day-ahead market price or the real-time price so that you can use the financial transmission right to hedge real-time prices as well as day-ahead prices.

I think there are certain kinds of projects that we've all heard about. My company's developed DC projects that typically have features that raise interesting new questions. I don't want to make too much about them, because I don't want to say that somehow they need some sort of special or differential treatment. Having said that, I think there are certain characteristics of those kinds of projects that make them more flexible within the market.

It's much easier to offer an option across a financial transmission right across a DC facility than across an AC network. I think as the market design moves forward, it would be in the market's interest for the RTOs to recognize some of the flexibility that projects such as

the DC project or other controllable devices, other high-technology transmission can bring to the table and can perhaps offer more of what the market needs through technology solutions rather than an endless reallocated discussion about how to slice the pie. It offers a way to actually bring some other desserts to the table as well.

In general, I think the financial transmission rights are an essential element to financing a transmission line, because they're an essential element to attract a customer. At the end of the day, it's the customers who signed up for it who finance a merchant transmission line. I would come back to the earlier point I made that I believe there needs to be an associated ICAP deliverability right tied to transmission expansions as well so that the entity that funds the transmission actually has multiple products they can offer to the market. First, the financial transmission rights in the context of, say, entirely within one RTO or a physical transmission right if it's between RTOs; and secondly, some sort of deliverability right so that the differential value of installed capacity can be recognized as well as energy prices.

And with that, that's enough to elicit efficient market investments, we believe. When projects make sense, they will move forward. There is, of course,

the tension between how much gets built and the endless joking between local generation developers, merchant transmissions developers like TransEnergie US, DSM, and remote generation, but that's the beauty of the dynamic marketplace is that it works itself out in many instances. The best projects move forward. The worst projects either don't or are delayed, and new ideas continually come to the table.

So I think with that kind of framework, new transmission is financeable on a merchant basis. There may be occasions of market failure where there are elements where transmission is needed for other reasons. Market power mitigation or their particular economies of scale that simply can't -- that are simply too big to ignore, but I would put forward the notion that that would be the first line of defense against congestion is to let the markets work.

MR. MARONE: In areas of load pockets, I don't understand really how that system works, because when you build a transmission line to relieve congestion, it doesn't generate any new revenue in the system. The amount of load and the amount of generation dispatch stay the same. The dispatch pattern changes. The total amount of revenue stays the same, and in fact, if you're efficient in building the line and you relieve the

congestion, the total amount of revenue goes down.

So unless you somehow contract forward for that premium price, which is basically locking congestion in the future, I really don't see how transmission projects that fix load pockets pay for themselves.

MR. COXE: In fact, I will answer the question directly, which is you're exactly correct. The entities that are the logical customers are the customers in the load pocket. They have a need for additional transmission capacity, and at some point they have to make the choice do I continue facing exposure to congestion costs or do I enter into a contract to once and for all, or for certainly a long period of time, relieve or eliminate my congestion risk.

At some point they do. Our customers have done that, and that commitment on their part to financially underwrite the facility becomes the basis for moving forward. You'll always have the risk, of course, the load in the pocket may want to just wait and see if somebody else solves the problem for them. We don't jump out and build -- to solve the problem without the commitment behind it, but it can be -- but once -- I guess the fear of congestion can motivate the financial commitment.

MR. MARONE: So it seems to me the cost of the congestion relief is getting socialized one way or the

other. It's just over how big an area. It's either a voluntary pocket of people in the load pocket --

MR. SCHNITZER: The people that would benefit, that's not socialization. I agree with what Roy just said. There's a matching of costs and benefits in that model. That the people who benefit from this new transmission line and on whose behalf the decision has been made that the transmission line as opposed to paying a generator support payment to get a new generator to locate locally or something like that is the most economic decision. They get the benefits, and they pay the costs as opposed to spreading it over some very large RTO and having some central planner make that decision. They're very different in character.

MR. THILLY: Funding new transmission through property rights to market participants sounds simple, but I don't think it's quite -- I think it's very complex. It's very time-consuming to build transmission and very difficult. We've seen projects take eight or 10 years. The market's going to change many times during that period, and how you get the commitments way up front with respect to the transmission capacity that are going to hold for that period of time. There's also, I think, a significant free rider problem of people hanging back who are going to benefit through the additional capacity

because it isn't the specific amount that's needed by the guy who wants to fund it.

Finally, I think there's a concern that it would increase the market power problem that those of us in constrained pockets face, because we are in constrained areas, at least in part, because people haven't wanted to build transmission, because that weak transmission protects their generation, and I think we're going to see the use of these property rights in a very similar way.

So to me, it's much better to get that system built. All customers benefit by a robust competitive market. The simplest way to do it is to build the system, have the load pay for it, and everybody benefit through the competitive market. That puts the focus of competition on generation where it ought to be, not on trading transmission rights or getting value out of the -- the highest value out of the transmission right, which doesn't in and of itself provide any value to the customer.

MR. COXE: Maybe I can just put some historical -- well, not so historical perspective on this. I'll just put forward two points. The Commission approved the proposal for the transmission charges that we had offered for the cross-cable in October 1989 and by October 2002, three years later, will be in service, and we've

done that in what I think is probably one of the toughest permitting areas in the world. So I think entrepreneurs who are motivated get projects permitted, and we're not -- we would never even remotely entertain the notion of telling a customer that it would take eight years to solve their problem, because we know they're not going to sit still for that.

The second point is, I will take suggestions from anyone in the room who has a transmission problem they want solved, because that's the business we're in. We'll do it, and we'll do it on a basis that's agreeable to them.

MR. NAUMANN: I'd like to give a real-life example of how not having a system, as we're describing, of having the FTRs funded by those who benefit, what you end up having. We've had a large amount of generation located in our service territory in Illinois, by this summer we'll have about 8000 megawatts, since 1999.

Some of that is being used or wants to be used to serve Wisconsin, and it's taken, I gather, listening to Roy, the last firm transmission service available to Wisconsin. However, the generators, in spite of the fact we said go north -- that's not what Horace Greeley said, but we said go north, went south, and we said south is not the place to be, because in order to get to the load or to

get to the places you want to sell, it's going to require transmission upgrades, and that's going to cost money. And they said that's fine, we'll go south. You just build it and roll it in.

And that's the problem. You lose -- you lose that price signal, so that in this case, the amount of transmission upgrades we've been required to do in Illinois to support these generators, many of whom are exporting, will fall on those connected in Illinois, not at all those who benefit.

Now, clearly, everyone has to take some burden for the reliability, but had we had a system in place where the generator could have come and received the FTRs for -- in this case, it was not a new line. There are things you can do to get more capacity, but they're not necessarily cheap. But had they said we're going to fund it, we'll get the FDRs, and that way we can deliver that power, I think that would have been a much more preferable solution than dumping the cost on the residents, the customers, in our service territory after we're out of a rate freeze. So right now, as a matter of fact, it's free transmission. This would get this done in the right way.

MR. MARONE: But that's the opposite situation. You're talking about a generation pocket where people had the option to choose, and if their option put them at a

disadvantage, I don't have that much sympathy for them, but a load entity who did not foresee retail access coming in three years, I think, has been put at a disadvantage. Some investments were made for a 20-year time span five years ago, and then the rules changed, and now you're in a load pocket.

MS. MANZ: I think this was why the property rights discussion we had earlier is really important, because if those folks that are in the load pocket want to do an upgrade -- and I don't necessarily in our area see lots and lots of new transmission lines, but I do see a real possibility for enhancing weak components in the system to get a benefit in a pretty short time frame. The important part is the loads that are in that pocket now have access to a new portfolio, if you will, or a broader portfolio, and that's going to be of value to them. Somehow you may see a generator that wants to access this load or this load that wants to access more generation. Either you will have -- and I look at transmission as a market participant in the planning or longer term horizon, that you now have options in the load pocket to, first of all, get some good demand side going, and the hope is once you have a market you can do that.

In PJM, we see where the prices are high, which is generally where the load pockets are new generation is

citing. So that would also solve your problem. Or you can get some new transmission into the area. And in all three of those scenarios, you're accessing a larger portfolio to serve that load. I think under all cases we want to make sure that we don't socialize these things, because when we start to socialize we're undercutting the price issues we're trying to put in place.

MR. MARONE: A lot of load pockets are metropolitan areas. Metropolitan areas are not good candidates for generation. They're uneconomical. They're difficult to build. There's pollution problems, high land costs, taxes.

MS. MANZ: I agree with you.

MR. MARONE: Generation as a solution has a lot of economic disadvantages. The other issue --

MS. MANZ: If you don't price that load pocket high, then you're right, the generators will go where land is cheap, where labor is cheap, where all these things are really easy for them to fund, but then they'll be really far away from the load, and then it looks like you need a transmission upgrade. So the lack of pricing makes it look like you have a lack of transmission.

MR. MARONE: But if you have economic barriers to building the generation in a load pocket and then you signal that with a premium LMP and then somebody builds,

the premium disappears, and he's left with the high costs and no premium.

MS. MANZ: And the cost to serve the load has gone down in that case.

MR. SCHNITZER: I think the implicit assumption there is the congestion magically goes away. These are not step functions. They don't need to be step functions. They can be continuous. If the load pocket is big enough, they can support new entry and still have a price high enough for that entrant to get their money out of.

So I just don't see that, you know, particular argument. I think to Roy's point, I think if we knew that building transmission to reduce or eliminate congestion was cheap relative to new generation costs, I'd say have at it, that's fine, let's just socialize all those costs and let the competition and generation begin. But empirically on the margin I don't think that's a true statement, or at least it's not a true statement everywhere, that there are circumstances where the difference in transmission costs that a generator can impose on the system can be on the order of several hundred dollars a KW for that generator. This against an installed cost for the generator of \$500.

So if you've got transmission differentials of a couple hundred dollar a KW on a \$500 per KW investment,

that doesn't strike me as being de minimus and we ought to ignore it and socialize it. It sounds to me like it could have a material effect on where the generator locates and should have a material effect on where the generator locates. It seems to me there's some danger in saying all the action is in the wholesale market, as if location doesn't matter, because I think location does matter.

MR. MARONE: The other issue with demand response, I think, when you're talking about large metropolitan areas, they're not good candidates for demand response. First of all, nobody has time-of-use meters, and secondly, a lot of them are resistant to demand response programs. They don't have a lot of --

MS. MANZ: I work in a large metropolitan area, and the first issue is do you have a market structure that can support demand response. That's the first thing you have to get in place. Then the next part is do you have some conductivity between the prices the customers see and what the market prices are doing. That may be disconnected, it may not. And so then you get to the issue of can you measure what the customer's usage patterns are in relation to the market prices. And you need all of those components in place before you can have a demand response program that works.

MR. SCHNITZER: I think the predicate there

that you don't get new generation in metropolitan areas, I think, is not true. I'm not the expert in New York State, but I believe even in Manhattan, there are pending projects within the New York load pockets that are being permitted and being constructed. I believe your company is building generation inside a load pocket in Louisiana, for instance. So I believe that there is empirical evidence that generators do show up inside of these load pockets. It may not be the cheapest place of anywhere they can locate, but the question is transmission cost adjusted, is it still the cheapest place to locate.

MR. MARONE: I agree that people do build generation in load pockets, and the area -- that load pocket happens to be an industrial area. So it's very convenient to do it. A lot of these opportunities have existed in Delaware since 1999, and it still suffers with 50 percent congestion. 50 percent of the time it's a congested market.

MS. MANZ: That doesn't mean that there isn't expansion and new siting and demand response efforts going on, and a lot of times what we see is that the market responds after the prices are in place, that if you look at, let's say, New England, for example, you still have the problem that no generation is going to southwestern Connecticut. I think until we get the price signals out

there, you may not see anything going. People tend to be reactive in responding to --

MR. MARONE: Part of the issue in Delaware, too, is the transmission owner that needs to do the upgrade is not the transmission owner exposed to the pricing problems. So Connecticut needs to upgrade its line, but it's the co-ops in the south that suffer.

MR. WALTON: And that's one of the advantages, I see, of us moving towards RTOs. I can't speak for that area, but certainly in our area, that moving toward an RTO means it's that much easier for alternate parties to come in and build something if they can.

I would also point out that metropolitan areas are also exceedingly difficult places to put transmission. If anything, it may be more difficult to put transmission through metropolitan area than it is to put generation in a metropolitan area, especially overhead kind of stuff, and underground is very expensive.

There is also, however, another issue here, and that I want to bring up with regard to this expansion issue, and that is the question of whether everything gets expanded under the congestion model. Is that the only model for all expansion? In general, especially in our area for long distance, everyone acknowledges that's probably the best way to do it, the forward sale of

capacity is an appropriate way to manage that issue.

However, there has been a concern that for local adequacy for transmission -- what's been called local transmission adequacy, that there had to be a backstop, that there had to be some way to ensure that as the load grew in an area, even though it's always on the downhill side of a transmission -- from the connection of the main transmission grid, that that transmission be kept up and be kept adequate, for instance, to serve both retail and wholesale load.

And so in the process of doing the planning, we built in a backstop for an adequacy requirement and a backstop provision so that if there's market failure, that there's some way for transmission to get built. Now, the anxiety of having done that, the tension there is that if you do that, then there's the fear that you've undercut the congestion management system, which you want to put in place. We, in fact, have generators responding to price signals right now. Steve Naumann's example was exactly like the reason we have a whole bunch of generation at Hermiston, because two pipelines cross there.

Now, it's on the wrong side of the congestion, but there's no penalty right now in the -- for the electric side. So they add up all the numbers and say that's where I'll put it. There's two pipelines there. I

can make them compete. When we put this congestion management structure in place, now they're going to get another signal that says oops, that may be the wrong place. Traditionally -- most of the network I'm familiar with, most of the projects I helped to build in my earlier days were all driven essentially by forward sale of the capacity. What was really happening was I wanted to build a generator in Wyoming or in southern Utah, and I wanted to deliver that load somewhere else, but the system was congested. It wasn't -- we didn't think of it that way. We said it didn't have enough capacity. If we had this system in place, it would have been congested.

In this case, the builder made a decision to pay for the transmission to make the delivery, and that went into their calculus of being able to have a load energy price. So the danger of this adequacy and backstop is that you don't want to undercut that. At the same time, there's a concern that if you don't put in some sort of a backstop, that you could get into situations, perhaps as Delaware, where there's a chronic problem, that there's just too many people spread out and you've got a market failure issue and no way to address it. That's how we've tried to balance the tension in that issue.

MS. MANZ: I want to be very clear that we don't confuse high prices in a congested area with

adequacy. Adequacy is when you're out of generation to redispatch, and then that's a problem. But up until the time that you have something to redispatch, that you can allow the prices to go higher, it's really not an adequacy problem as much as it's a price issue.

And so what we look at is do you have, in fact, a reliability problem, and that's when you may have some sort of backstop mechanism to come in and build more transmission infrastructure.

MR. WALTON: And I agree with that. What I am raising is there are parties to these collaborative discussions we've had for some time who are concerned that there's a possibility of a market failure, that the benefit is spread so widely -- I mean, there's always the free riders. You always have a few free riders, but if the benefits are spread so widely, then is there a way to collect them up and get the investment made if it's only the market signal happening.

MR. SMITH: I think another issue, too, in terms of mitigating the price signals, it's my belief that as long as you have sufficient price signals, it's going to encourage innovation and creativity to solve some of these problems where maybe it is difficult to site generation or to build new transmission, but if we meet those price signals, we're certainly not going to get any

innovative or creative solutions. I think as long as those price signals are there and there's an economic benefit, somebody's going to figure out how to capture that benefit, which is going to decrease congestion costs for everybody.

MR. MARONE: But the pricing doesn't go forward unless you contract for it on a going-forward basis and what good does that do the retail customer? You've put in a solution, and who did it help?

MR. KELLY: Let me jump in with a question here.

MR. SMITH: The one with the contract.

MR. KELLY: The system you're talking about seems to work well when you can identify the beneficiary and the beneficiary gets the FTRs and pays for it. But I can think of so many examples where the beneficiary would either be hard to identify, impossible to identify, or at best controversial. We're building additional transmission here, relieves congestion on a system 500 miles away, because there were loop flows that were relieved by building the new system. They're generally increasing the reliability benefits of the system where the danger of one line going down is relieved because now there's another line to take the overflow.

Building a transmission line between, say, two

areas that are fairly well integrated may simply increase the option and ability of people in one area to buy power from another area, increasing the size of the market or maybe increase -- take an area that was out of bounds for reserves because there was too little transmission to make that area in bounds for reserves. I can easily see that there could be many debates over who are the beneficiaries, how they're allocated, that could make it difficult to simply say well, we'll allocate FTRs to the beneficiaries, and the beneficiaries will pay.

MR. SCHNITZER: It's a good question, Kevin, because we're obviously thinking about this a little bit differently. I think the process you're describing is somebody decides this is a good investment, makes the investment, and then goes looking around for the right people to charge for it, and that would be a problem of the character that you described. I think the process that I'm talking about, I think that Ray is talking about, is that somebody or bodies come up with an idea, says I can do the following project and it will have the following consequences: it will create the following FTRs, it will create this ICAP deliverability, it will integrate this resource into operating, whatever it will do, here are the set of property rights associated with it.

Who would like to contractually sign up for a

stream of payments in return for those property rights, and then we'll go out and make the investments, so that the allocation is done, in effect, by people betting their own money. Central planning doesn't decide it's the right decision to make and we go look for people to allocate to. We put a project out there with a set of associated property rights and we ask for people to come in and sign up for it. If they do, they pay for it.

MR. KELLY: Would it be fair to say that the system that you're espousing might, if anything, underbill transmission, and the one I was articulating -- I'm not espousing -- if anything is underbuilt transmission, and between those two which would be the better? Just to tell you the follow-on question, is it possible to have the two together? Is it possible to have a system where those who want to get transmission built, and they're willing to pay for it, can do so, and in addition, if there's a general grid need, there is an entity, perhaps the RTO or a committee of the RTO, that pursues that also and spreads the cost, or does that simply dilute the incentive of those who would pay for it themselves to try to politically get their preferred project into the first category.

MR. SCHNITZER: That's another good couple of questions. Underbuild versus overbuild is a little bit of

in the eye of the beholder. The type of investments we're talking about, expansion-oriented, are inherently risky projects. They compete with generation. That's what they are. So whether it's underbuilt, well, at a 30-year time horizon, 10 percent discount rate, somebody might decide yeah, you're underbuilding but that's not the time horizon for generation investments. We would assume that those would be the ones that would pass the hurdle that market participants would sign up. They would not, I don't think, have 30-year time horizons and 10 percent discount rates. I don't view that as underbuilding myself.

MR. KELLY: Maybe I should have phrased the question, if one system builds less transmission than the other who builds more.

MR. SCHNITZER: I think it's possible that would be the result. As to the mixing of the two, I think in some sense you have to have some kind of backstop, as it's been described. The question is how narrowly do you circumscribe the backstop. There's a lot of ways to avail yourself of the backstop. Then you do have the problem to which you alluded to, the low-hanging fruit that's going to be very profitable to do one way goes that way and all the projects that gee, this would help me but only if 80 percent of it were paid for by somebody else goes into the second bucket. That's not a particularly efficient set of

outcomes either.

My own view is we need a very narrowly circumscribed backstop that is very hard to get to. The presumption ought to be in the first instance, that if market participants are unwilling to fund it themselves, show me a very good reason why that isn't the right answer.

MR. COXE: I might suggest of the two systems, while you're correct one may build more or less, I would claim that one system does build smarter transmission, and that's the system where people are betting their own money, in effect. I think while maybe nobody in this room has met a stranded transmission line, they're out there, and they'll exist in the future.

And I'd also come back to a point another speaker made earlier, that if an RTO undertakes a mission to eliminate congestion at all costs, without regard to what social purpose it's truly preserving, you continue to send -- have generators locate in the wrong places, and you'll continue to have demand side just not participate because it's not seeing the social costs associated with decisions to put a new office complex in a load pocket, and there is a real social cost of that. Should it be socialized? Should we subsidize that? Maybe, but let's not do it without making that decision.

I do think regulated investments driven by an RTO planning process and merchant investments can coexist, but I would agree with Mike that -- and I'd even be perhaps a bit more generous than Mike. It can be narrowly circumscribed or not, but what they need to be is clear so that market participants know that if they don't step up to this, it won't get built, or they do know if they don't step up for it, it will get built and nobody will try to build that project on a merchant basis. What I don't want as the developer is a lot of merchant transmission projects to discover an RTO that is now on a mission to build projects that effectively compete with mine on the basis of assumptions and futures that may or may not materialize and in effect the planner isn't putting their own money at risk.

I think as long as the planning process is well-defined so that I can understand -- I and merchant generation and load developers can make their decisions based on a fairly clear vision of what the RTO will and won't do, then I think it's fine. But an RTO that's shifting gears, that blows one way one day and another way on another will just discourage everyone.

MR. THILLY: If I could say, first of all, I don't think we'll have an RTO that's going to build transmission at all costs to avoid congestion. I'm not

worried about overbuilding transmission. I think it's very, very difficult to build. I'm very much in favor of getting to an adequate and robust system that will support generation competition. We need a regional planning process. We need a public regional planning process for transmission. We can't ignore state siting, which is going to look at need and is going to look at whether generation is a better solution. People who try to stop transmission lines always argue that the generation would be the less expensive solution, and state regulators are going to look at that. I think it's naive to think we're going to get bidded out, a couple investors are going to come along and be able to build the transmission line.

That just simply is not going to work in the real world of the states. An RTO open planning process that identifies the best solution and has that muster behind it is much more likely to get facilities built that we need built to relieve congestion.

MR. WALTON: This really takes us back to a discussion we had at a panel three months ago with Laura sitting right here next to me then as well. There's another class of issues there, too. I think the preferred model is the one Michael Schnitzer describes. That's the preferred way we would like to do that. To the extent it doesn't work -- it's true we'd like to prescribe the

exception as much as possible, but there's another class of problems. There's a class of problems where because of regional planning you decide that the low-hanging fruit ought not to be taken care of.

In other words, someone should not be able to take and use a corridor -- less valuable corridor for a lower voltage facility because that produces as much capacity as they want for now and you force them to go to a higher voltage facility. I give that as an example.

There are other examples. And in those cases, then you have to say well, the greater social good is to force the voltage -- or is to get the construction of the high voltage.

Yet, you have a group of people who are willing to put up a substantial part of this in order to get the project to go. So then you need to decide well, how can we get the rest of that money, should it be distributed across the whole network. So what you need inside the RTO, in its planning process, in addition to being able to do all these things, you need a decisionmaking process that can take these on one at a time -- there's no way to handle these problems generically. They are specific to the example, to the corridor, to the timing, to the year, to the facilities -- and get that done.

Now, having said all that, I think the reason

that the -- that I believe that the expand to eliminate congestion model will really work is not the intermittent congestion and those sorts of things. It will be that remote generation wants to compete with local generation and is, therefore, willing to pay for transmission. It's really the remote generation competing with local generation, not transmission competing with generation.

MR. O'NEILL: Steve, was that the Candyland example?

MR. WALTON: That was the example I used before. You're very astute.

MR. O'NEILL: I was listening.

MR. MARONE: I would like to vote for more robust. I've got 5 percent of my bill that's torquing 75 percent of my bill. So my preference would be to err on the side of more robust. And I think RTOs can be just as prudent as private investors. I don't think that RTOs attract people that are not as creative. I think if the proper incentives are put in place in the RTO, they can be just as creative and inventive as anybody else.

MS. FERNANDEZ: I was wondering if this might not be a good time to sort of switch topics. I think we have a few minutes left before we get into -- I'd like to have an opportunity for the audience to ask questions. One thing that I noticed we didn't talk about -- we had a

fairly lengthy discussion on options and obligations -- is that we didn't get into flow gates and trading hubs.

And I guess maybe sort of a general question to the panel, in terms of when we're looking at the hedging rights, to what extent should there be flow gate rights, options, or obligations, and also, to what extent or how, if you believe it should be done, should trading hubs be encouraged?

MR. DOYING: I advocated for all four, so I will jump in first. I think the issue is that we should offer anything that's feasibly and can consistently be offered to the market. Again, there's no reason to arbitrarily limit what's available to market participants in terms of hedging instruments. I think we've wisely decided that we can't divorce the transmission from the energy market, that they're so tightly linked that the RTO has to be either overseeing or very closely integrated with someone who is overseeing that market. We just can't unbundle them.

As a consequence, I think we don't have a choice but to then allow the RTO to offer all of the products to the market at once in terms of hedging instruments for transmission. Those are instruments that only the RTO can sensibly offer. I just can't imagine why we would want to limit the ability of market participants

to hedge risk. We're not going to lower liquidity.

If you just offer everything that's feasible and consistent, the market will decide which ones they value the most, which ones they want to trade, and the market will refine. We can also arbitrarily limit and the market will work and stumble along that as well.

But if what we're looking for is the most liquidity we can get, the most competitive, the most efficient outcomes, I think we should unfetter the market and let it go. We don't need to mandate that they should do the impossible, but we should tell them to offer everything that they can as they can do it.

MR. NAUMANN: I think this is at least as far as flow gates is a matter of practicability, and again, I guess I keep coming back to when a standard market design is going to go into effect for the RTOs. This has got to work, and it's at best unclear that flow gate -- financial flow gate rights, whether they be options or obligations, that the software is developed, that it's workable within the system, that you're not going to overwhelm the point-to-point FTRs to the point that you're not going to have sufficient -- that one critical flow gate won't eat up all the FTRs. So yes, choice is good, but are we going to have the choice in '03, or are we going to have the choice in '05?

Again, I come back to it needs to be --

whatever is done needs to be workable, needs to be shown

that it works, and it has to be better than what you have.

So I would say it's a nice theoretical problem. In the

last year and a half, the definition of what a flow gate

right is has changed, you know, three, four, five times.

Let's lock the system down and work on it and make sure

this works before we go commit to saying we're going to

have these rights.

On trading hubs, that would be an excellent

idea, to be able to have point-to-point rights from one

hub to another. That should be very helpful to the

market, and I think there's some experience that shows

that that will work.

MR. SCHNITZER: It's hard to be against having

more options, but I think under the condition that they're

feasible and rigorously consistent. So I guess the flow

gate concept, you know, if they prove to be feasible as

financial flow gates and if they are designed in a way

where they settle against actual congestion so that

there's no implicit socialization or anything like that,

then I don't see any problem with them being made

available at some point as an option.

I agree with what Steve Naumann just said, that

that's unlikely to be a day 1 type of capability. We

shouldn't hold day 1 until we can do that.

Trading hubs, I would also echo Steve Naumann's comments. Just to point out, though, I believe there's some interaction between some of these things, and I'm not the expert in this area, but as I appreciate the decomposability of FTRs, which you would want for hub to hub -- you want to be able to decompose FTRs in hub-to-hub, hub to load, it is different for options than for obligations. So you may affect some of your options and your liquidity in your hub-to-hub FTRs.

MS. FERNANDEZ: In terms of options being harder to do as obligations?

MR. SCHNITZER: Yes.

MR. COXE: One possibility is to consider -- and I will use the Christmas analogy. If you want to build the Lego castle that has the knights and the dragons and the walls, you go out and buy the Lego set that has all kinds of blocks that build up to the castle and maybe a lot of them are 6-by-6 or 10-by-10, or you can just buy lots of 1-by-1 pieces and build the castle, but then you can also build other things.

To come back to the point of that, starting with point-to-point financial obligations, I think everything else can be constructed off of that or should be referenced relative to that, and I don't think we

should necessarily presume that the RTO is the only entity that's going to be able to construct other flow gates or construct trading hubs or arrange for other options.

Any financially qualified provider can enter into the business and assemble a portfolio of a combination of resources, be they FTRs, generating options, what have you, and deliver to the market things we haven't thought of and the market doesn't know it wants. So I would, perhaps, urge, suggest simplicity in what the RTO does to allow complexity in what the market does.

MS. MANZ: We use them, we like them, trading hubs. We actually have two different types of hubs. We have trading hubs that are fixed weighted hubs, and then we have what I would call settlement hubs, which are low weighted hubs. They can actually both be used for trading. Just as an example of how this works pretty well is that you have flexibility.

So a couple of weeks ago, we started a new settlement hub for trading, because we're auctioning off the New Jersey basic generation service, provider of last resort. And so we've now designed a hub that is New Jersey. And so I think what's really important in designing these hubs is to make them as flexible as possible, which you can get through the recombination of

the nodal prices, and it works very well.

MR. THILLY: I would second what Steve said.

Flow gate rights are complex, and they are -- it's a constantly changing system. It's difficult for customers to manage them. A financial point-to-point right fits a lot better for a load-serving entity. Our concern is not -- if they can be offered, that's fine. It doesn't seem like a day 1 issue, but we're concerned that offering them may constrain the availability of the point-to-point rights and make it more difficult to serve load.

MR. O'NEILL: Can I ask a question? The Midwest ISO has essentially said they want flow gate rights in addition to FTR point-to-point rights. Yet, the two people here from the Midwest ISO are saying gee, that's not important -- I'm sorry, close to the Midwest ISO.

MR. NAUMANN: I'm not sure if the discussions have adjourned for today or not.

MR. O'NEILL: That was a mistake. In the Midwest.

MR. NAUMANN: If we could have a caveat on this end of the table. Having attended only one of those meetings, I would say that's a hope -- that's hope, wing, and prayer that software developers are going to be able to do it, and without solving the availability -- knowing

the availability problem in advance that Roy just brought up, these are nice theoretical discussions for mathematicians and engineers.

MR. O'NEILL: The point is they're proposing here to -- we have a proposal in front of us that they're going to do that.

MR. NAUMANN: The details of what's going to be available, which rights are going to be available, how many flow gates, which flow gates, all those little details that ultimately make the system work, I don't believe any of them are really, really, really solved.

MR. WALTON: I point out we put 18-plus months into flow gates, and we loved them and we admired them, and we abandoned them.

MR. SMITH: My view is that option, though, is good. I would agree with some of the comments we heard earlier, that that shouldn't be at the expense of getting a standard market design up and going. And to me, the issue, both on the types of hedging instruments as well as the trading hubs, is that we put in place the fundamental building blocks that are required in order to facilitate that.

I think an LMP-type system lends itself very well to developing trading hubs. You have vocational prices that can then be aggregated to form those hubs. I

would be an advocate to allow market participants to determine how those hubs should be defined as opposed to having the RTO do it.

There are a lot of existing over-the-counter products that are going to be affected by how those hubs are defined. And so, you know, I would just say let's put the fundamental building blocks in place, provide options, and then let the market determine how to structure those.

MR. DOYING: Can I turn the question around?

Someone who has worked on the Midwest ISO development process for a couple years now, let's assume at the end of the day they walk in and have a pretty fully flushed out model. The software developers can actually do this. I can offer point-to-point rights, flow gate rights -- we'll define them in some way.

Steve's right. You can define them a lot of different ways. Options and obligations, we can auction them simultaneously. The market will clear, and it will tell us what all these things are worth.

What will you -- on what basis will you evaluate that package, and how will you decide whether or not that's something that's in the public interest to allow an RTO to do?

MR. O'NEILL: Options and choice are better than no options and choices.

MR. KELLY: One factor might be -- turning your turnaround question back to the panel, does that create problems in a neighborhood that doesn't offer both?

MR. DOYING: I don't think it does, and I will tell you why. Again, we have to distinguish between a financial market -- which is an overlay on top of a commodity market, and they're solely to allow people to hedge financial locational risk, and that's -- so that's the energy market we talked about this morning -- and these transmission rights.

As long as congestion is cleared on a consistent basis across that RTO system and as long as physical property delivery is priced the same across that seam, then the only thing that's left for market participants to do is to figure out how to hedge that basis risk, and then do that with any combination that the RTO might offer.

This is the critical point. Let's say you have one RTO that comes and says we've solved the problem and we can offer all four and they're next to an RTO that only offers point-to-point obligations but they offer the same product at the border, and if people feel the only way to hedge that risk is to make sure they've got that specific type of financial instrument, it's available in the market. The fact that they also have the choice to buy

other options or other products to hedge their risk for other transactions doesn't really impact the ability to transact seamlessly across that RTO.

MS. FERNANDEZ: Can I take it from that -- and I think some of the general discussions seem to be that there's a lot of concern about delaying things and that getting something good started is more important than getting something perfect started several years later. I mean, is it something where you -- if you offered point-to-point obligations -- I mean, that's been tried. People know that it works -- that that's a requirement, and that if RTOs wanted to offer other products based on the desires of market participants, they could. The products that would be offered, standard products might also be reexamined after a year or two of operation to see if anything should be added. Is that something that would be workable?

MR. NAUMANN: I think that is exactly what we would recommend. The only thing I would want to add to that is that as you go out and do your software procurement, whatever that means, for your system and you say okay, I want to offer, in addition to the standard products, I want to also offer, let's just say, flow gates. Now your software may not happen, comes in six months late, and the market is six months late.

That's what my concern is, from someone who wants to see the market up and running. I mean, I think the way PJM has done it is they've got their basic market, and now they're talking or they're close to doing something with options.

Again, we need to define the term. In doing that incrementally, I think it is very good and choice is good, but when you do get into software development, you are taking this time risk, and that, again, would be a concern for those of us who want to see the market, you know, in operation in 2003.

And to be very honest, I think that 2003 is a realistic time if we're starting on the time scale that you're talking about, of a final rule before the summer, which, I realize, is aggressive. So that's -- I guess I'm agreeing with you, Alice, in general, with a little bit of warning about software development.

MR. MEAD: Switching subjects a little bit, in terms of the nature of financial rights, I've heard at least two -- at least in one characteristic I've seen two different proposals. On the one hand, there's the RTO West's notion that a financial right is one that allows the holder to hold payment of congestion charges. Then there's the right that you see in the three eastern ISOs currently where the holder of the right is entitled to

congestion revenues whether or not there is a physical schedule of transmission associated with it.

I have sort of a two-part question. Do we need to -- does our standard market design need to choose between those two? And if so, which is the better way to go?

MS. MANZ: We're all going to raise --

MR. NAUMANN: Absolutely. You get the FTR payments whether you schedule or not. I think what you will find in reality is that the schedule might not actually match one for one your point-to-point rights, and why should that matter if you're doing things on a portfolio basis. So yes, you need to specify it, and the PJM-type model is the one that should be specified. Hopefully Laura will agree with you.

MS. MANZ: Yes, I will agree with you. One of the things we're seeing is a general shift when you go to a market where you have complete flexibility. You can have a balanced schedule if you want it, but there's no requirement to have it. You can just buy, you can just sell, whatever you want to do. Then the notion of a transmission schedule changes to the obligation to pay off the system.

And so the schedule -- the notion of a schedule is kind of decoupled from how you use the system. And

that's the shift we're seeing once we go to these open markets, that there's an obligation to pay off the grid, but there's no obligation beyond that.

MR. SMITH: Before Steve rebuts, can I agree with --

MR. WALTON: I'm going to wait until everybody else disagrees with me.

MR. SMITH: I think they should be specified. I think you should see the congestion rents whether you schedule or not.

MR. MEAD: For the three of you who said yes, we need to standardize this, I'm not clear. Are you suggesting that if we don't, that there will be less trading across RTOs, or is there some other problem that will be created? If the Midwest ISO decided that they wanted to go the RTO West route and PJM stuck with where they are right now, would there be a seams problem?

MR. NAUMANN: Let's assume for argument sake that the second half of Exelon, the western half of Exelon is in the Midwest ISO and the eastern half of Exelon remains in PJM, and now it becomes much more difficult to do business -- it becomes easier than it is today obviously, but you have this problem of different business practices in coordinating our system between the eastern half and the western half because the Midwest now has this

different rule on how you treat congestion, and there are loop flows between RTOs and all these other things. So why create the additional problem?

MR. SCHNITZER: I don't see that so much as a consistency across RTO issue as what's the right answer or what's a good answer. And again, these things are all linked together, but one of the desirable features of the LMP financial rights market that we've been describing today and previous days is that it's neutral with respect to bilateral and spot purchases out of the exchange.

As I appreciate the "use it or lose it" characteristic that's being talked about out there, unless -- if I choose to buy out of the spot market, unless somebody's going to go figure that there was a congestion part of my bill, you know. Then an option that I have, which is to buy spot and use an FTR to hedge my spot purchases, I can't get. I can only get it if I schedule a bilateral, and indeed, I can only get it if I schedule the right kind of bilateral.

If any kind of "use it or lose it" provisions were permissible by FERC of that character, it would undermine the basic neutrality that we're trying to build in the market structure between spot and bilateral transactions, and would be objectionable for that reason, not for a seams reason.

MS. MANZ: I guess I have an additional frustration, that even when the markets are seemingly alike, we still have seams. And so I think an important part is to not only have the building block, the LMP, the point-to-point obligation rights, the things that we've talked about today, but to make sure that there's sufficient data infrastructure so that you can have sort of this network regional market that I think we're beginning to see emerging, that it's important not only to have the building block but be able to share data with your neighbors so that you can have a market that expands that original control area, because we've seen an almost identical market designs create seams issues anyway.

MR. WALTON: Now that I know everyone doesn't agree with me, first of all, there's a couple assumptions people have made in their answers that are not correct, and one of those has to do with the fact that if you have congestion -- it just says if you have congestion costs, in other words if you're using the system, that would be the exchange.

That doesn't necessarily mean it's tied to a schedule necessarily. In other words, if I have congestion costs and I held this set of portfolio rights but my use is actually over this, we're going to make those fungible, it doesn't matter, it doesn't matter

whether they're fungible.

The issue here is this. Some people had said that the reason there wasn't a particularly strong or a viable secondary market in PJM was because they allocated. Well, if that were the case, why isn't there a viable market in New York because they didn't allocate, they have an auction. The reason -- the problem that I see with these as they stand now is that if you acquire them, there's absolutely no -- there's very little reason to sell them, and there isn't much of a secondary market.

And we were talking -- our intention with this feature in fact is to create a secondary market in the transmission rights so that there is an incentive for someone to release that right or to resell it to someone else, and that's the feature.

It's true that there's the virtue of the financial right as defined is that it divorces use. It's also the vice. It doesn't have any impact in a self-scheduled system, largely self-scheduled system as we're going to have in the hydro system, on having any impact on the way people do business, and we think that that's a virtue to be had.

Now, I understand what people have agreed. I've heard the same arguments for a long time. I still -- our purpose or intention was that we have a secondary

market in these transmission rights, that people who hold them have a reason to release them if they're not going to need them rather than just camp on the cash that's coming in. I can see a regulated utility being in a position to say if I release these rights, if I sell them in the secondary market, if I lose money, the Commission will nail me. If I make money, they'll take it. What's my incentive? Don't do it, just sit on the rights.

If I don't need them or if there's -- somebody has a higher valued use, that's okay, I don't want to take any risk. We wanted to set up a system where there was a secondary market. This is the mechanism we came up with that we thought would do that.

MS. MANZ: I want to respond to that, because first of all, we believe there is a pretty strong secondary market for FTRs, but I think there may be something else going on here, and it's the nature of the LMP market that automatically sells A to B, because you automatically collect the money for the FTR that you held, and if you want, let's say, X to Y instead, you can be willing to buy through congestion, and it automatically happens. And so I think maybe the lack of all the activity is maybe a characteristic of the LMP model itself. And so I'm not sure -- as I said, I think we do have a pretty strong secondary market in FTRs.

MR. WALTON: If you went into the reconfiguration auction right now and you were to ask for an east hub to west hub, I think the possibility of getting that is really remote.

MS. MANZ: My point is, I could today or even an hour before I want to take a transaction from east hub to west hub, be willing to buy through congestion, and that's all I have to do. It automatically happens.

MR. WALTON: Right. But you have no way to hedge that deal. You have no way to hedge tomorrow's deal that you decided to make between the east hub and the west hub because there's no one going to sell you an FTR for tomorrow.

MR. SCHNITZER: At what price, Steve?

MS. MANZ: That's the question. They're all posted. You can buy one.

MR. SCHNITZER: At \$5 million? At \$1000?

MR. WALTON: In that case why isn't there a daily market in FTRs? I haven't seen it.

MS. MANZ: Well, the FTRs sell daily.

MR. WALTON: The FTRs don't sell daily. Transmission sells daily. FTRs sell monthly in a reconfiguration auction.

MS. MANZ: I can buy FTRs any day. I can collect money from my FTRs any day.

MR. WALTON: From the RTO?

MS. MANZ: Yes, I would get them from the RTO.

If I want to buy bilaterally, I can buy them bilaterally.

My point is that I get the equivalent of buying through-service just by being willing to buy through congestion, and that if I want the hedge, I can try to find one that somebody's willing to sell, but I have to be able to --

MR. WALTON: You've made my point.

MS. MANZ: Okay.

MR. NAUMANN: I think having shown -- or feeling the wounds of a year and a half or so of discussing things like, as a colleague of mine put "use it or lose it," a new kind of label, a new kind of pasta. There's a problem. You now have to make some arbitrage rules as to when this is going to be released. You then run into other issues, as some of the industrial colleagues in our territory have brought up and have said look, we have on-site generation. That's what we normally use. We have backup generation that's remote. We want to be hedged for that.

If you have a "use it or lose it" rule, well, we're running our on-site generation at trips. We've lost our hedge that we've just gone out and bought because we wanted to ensure our delivered price. You've taken that

away from us. So now we're going to make a special rule that these things are recallable, and we're adding rule upon rule upon rule and complexity on these things. The same thing with distributed generation, which could be in the same situation as a cogen, counting on a backup supply and wanting that FTR to assure the price certainty.

So there are problems with having a "use it or lose it" rule, and you're just going to, each time, make rules to fix an actual or perceived problem, and you're going to put, I think, matches on matches, and with a pure financial system, there simply is no need for that.

MR. WALTON: If there were a physical right, I would agree with you. That's why they banned physical rights, because you did have a difficult rule here. Here, the rule is very simple. It just says if you don't -- if you want to go out in the parking lot and burn your money, go ahead. If you don't release it, don't use it, that's fine. You just don't get the value. If you want the value, go sell it in the secondary market. That's what it says. That's all it says. There's no rule that says I'm going to take it away from you at a given time. It says you can use your judgment as to how far to go and so on. It is not the same.

If we were talking about a physical rights model, I would agree with Steve, that you have rules upon

rules upon rules, and in my initial statement, one of the reasons I pointed out for having abandoned physical rights is -- that's one of the features, that we had so many complexities trying to deal with the physical rights that we abandoned that, but that does not -- this is not that. This is clearly a situation which says if you want the value and you don't have a particular -- and you don't have a schedule or you're not using the system, then release the right to someone who is using the system and get your value from buying it in the secondary market.

MR. DOYING: I'd like to support Steve in terms of arguing against a "use it or lose it" rule. I am sympathetic to Steve's problem -- I'm sorry. I agree with Steve Naumann to not have a "use it or lose it" rule. I agree with Steve Walton that if you allocate the transmission rights you have a problem. You know going into the market you will have no liquidity in the market. And so Steve Walton said gosh, we know we're going to have this problem, what do we do about it. The answer is not to dream up an after-the-fact fix. It's to auction the allocation rights. Then you don't have the problem that Steve is trying to address with the "use it or lose it" rule.

MS. FERNANDEZ: I did want to try to work in some time for questions. Dick has one last question.

MR. O'NEILL: In all of this discussion this morning -- I forget exactly. I'm losing track of time. Somebody told me that the congestion revenues are only about 10 to 15 percent of the revenue requirements of the transmission system. Some of you, including Mike, so eloquently explained how having entities subsidize the transmission system that aren't using it creates efficiencies. What happens to the 85 to 90 percent of the transmission revenues? Is there a way to allocate them? If you allocate them to the load and the load wants to go out and build distributed generation, are there rules for the other 85 to 90 percent of the transmission revenues that help us get the right incentives?

MR. SCHNITZER: Are you talking about a transmission revenue requirement for the embedded cost?

MR. O'NEILL: I assume Steve is not going to give that issue up, Steve Naumann, I guess.

MR. NAUMANN: That's my name. You mean as a transmission owner, that I'd like to receive my revenue requirement?

MR. O'NEILL: Yeah.

MR. NAUMANN: It'd be hard to go home if I gave any other answer.

MR. O'NEILL: So are there any rules for efficient allocation of these -- that the rest of these --

MR. SCHNITZER: I think the rule that is implicit in the whole market structure is the independence of those transactions. It does not depend where your source and sink is, so we don't tie it to transactions. I think once you do that, you've got a whole bunch of do you have cost shifting or do you want to leave them where they are or all that kind of stuff. The rule number one is don't make it transaction-dependent. Choose some other metric.

MR. O'NEILL: I think the most we all -- at least most of the models sort of somehow or another tell the load-serving entities that they have to pick up the residual.

MS. MANZ: Dick, I'm really confused about what you're saying. If we're talking about the congestion revenue, that means that once loads have paid a higher price, generators are getting paid a lower price, and there's some money left over --

MR. O'NEILL: No. I mean you have a revenue requirement --

MS. MANZ: Which is independent of any congestion on the system.

MR. O'NEILL: And the question -- and my understanding is the congestion revenues, for example in PJM, cover about 10 to 15 percent. No?

MS. MANZ: The congestion revenues, in a perfect world, given that you do the simultaneous feasibility correctly, should cover all of the congestion.

MR. O'NEILL: And how much do they cover now?

MS. MANZ: I think it's 99.9 something.

MR. WALTON: Andy quoted 97.5.

MS. MANZ: That's why, Dick, we went to a longer time horizon. In the event you have a shortfall in one month --

MR. O'NEILL: No, no, that's not the issue. You have a revenue requirement; right?

MS. MANZ: Yes.

MR. O'NEILL: You also have congestion revenues.

MS. MANZ: No.

MR. WALTON: There's two streams.

MS. MANZ: My revenue requirement as a transmission owner is completely decoupled from anything PJM is doing with the revenue for the congestion.

MR. O'NEILL: I understand that. How do you -- but you net that back, right, to the revenue requirement? What do you do with the rest? What's the right rule for the rest?

MS. MANZ: If you overcollect so that somehow PJM has collected --

MR. O'NEILL: I'm not talking about the revenue adequacy. That's not the issue.

MS. MANZ: Then they're not linked at all.

MR. COXE: The usual economist answer is you stick the sunk cost to the nondemand response part of the system which is presumed to be load. So you stick -- you put that 85 percent of the cost on load, because you presume they're not going to change their behavior as a result of having it on there. Ideally, you'd like to stick it even to the particular piece -- maybe to residential load because they're even less demand responsive from an efficiency standpoint. You can tar me and feather me out in the parking lot. I will be distributing hot dogs for the bonfire.

MR. SMITH: What happens when the revenues come in is a function of the retail rate deal. If you get fuel costs and you get a congestion bill and you get congestion credits --

MR. WALTON: Are you talking about --

MR. O'NEILL: I'm saying, you have auction revenues that are attributable to the transmission system, the physical assets. You also have a revenue requirement, and those two aren't even close, it's my understanding, at least in the existing operation, and the question is, what do you do with the rest of the money that you have to

collect?

MR. WALTON: It seems like it's three revenue streams here. There's the revenue stream that comes from access fees, which should equal the revenue requirement. Then there's the stream of -- in the Northeast model, okay. Then there's the FTRs. There's the actual collection of congestion costs. That's another stream of revenues that's refunded through FTRs. Then there's the auction revenues themselves, the revenues that come from auctioning off the ability of the system. So there's really three streams. The auction revenues in most of these is going back to decrease the fixed cost of the system, I think. So how is that allocated back and to whom is it allocated? That's a good topic to talk about, but I don't know the right answer to that, but that is another stream of revenues.

MS. FERNANDEZ: With that, since we all look somewhat confused, why don't we see if there's someone in the audience that would like to ask some questions, or did we confuse them so much that --

MR. SHANKER: Thank you. Roy Shanker. I'm here representing a number of parties, but I guess the question is for myself, as I want to offer a clarification, and people can maybe comment if they agree. When we're talking about the auction revenue rights or the

allocation of rights and the issue of options or obligations, in the discussion I thought two things were getting confused. One is, we can have an auction revenue rights model, that is, it can be for options or obligations.

Somehow we give out entitlements, something to the participants, anyway you want, historic use to the systems, links between generators and loads, whatever you want, and those could be in the form of options or obligations, and those create some sort of allocator for money for the auction. That's one thing.

There is a separate thing going on, which was what do we do if we -- do we make things too complicated or whatever when we have options as a part of the base in terms of the initial auction structure, and what was going on there, if I heard -- I think this is particularly Steve Walton's comments, is what I'm hearing underneath this structure is the initial set of rights that are outstanding are not simultaneously feasible. People have overallocated the system, particularly, it sounds like, Bonneville from your discussion last week.

What we're hearing are a lot of machinations that go around having to deal with the fact that somebody's got to bite the bullet and tell people they don't exactly have what they thought they had. That's a

separate question that is -- to me, I'm hearing people driving rates and driving the allocation structure in a fashion to avoid confronting the fact that in Roy's case while he may have bought 107 megawatts, when they look at all the rights allocated simultaneously, they could only really guarantee him 100, and if I add up all the options that Bonneville allocated out, I can't do it all.

So everybody's only going to get 70 percent of their rights as a basis for their allocation of auction revenue rights or auction revenues, and those are two separate problems. We can have an option system that allocates revenues on an option basis. There's no reason not to do that, and that's very straightforward.

The first problem, which is hiding from the fact that the system's been overallocated, you can't. If it's overallocated, it's overallocated. Somebody's got to bite the bullet here and directly confront that. And some of this "use it or lose it" discussion sounds like we're circumventing a direct confrontation on the fact that you've overallocated the system.

MR. WALTON: There is an issue there. The issue is what I talked about, the catalog. In other words, if you have a set of rights that were issued, historically what happened is the party issuing the rights knew that not all of them happened at the same time. One

part peaked in the summer; one part peaked in the winter.

There were trades back and forth. If you were to try to conform them to a uniform set to one system and add all those pieces, without taking into account the netting, the natural diversity that takes place, you would be overallocated.

However, on an ongoing basis, because of diversity and because of netting, you don't -- that is not the case. So we said how do we honor the existing contracts and still get as much out of the system as possible. And the way to do that was to bring them all together and pool that whole set under this catalog so that each of the individual parties have the flexibility they originally had, but we were still taking advantage of the diversity, and then out of that pooled set, we could now release more than we could otherwise.

So in fact, we tried to confront that head up, and you could have gone the route of saying okay, we're going to do a standard product and going to pro rata everyone down, but that was unacceptable to the contract holders, to the collaborative partners, and also to the utilities themselves. So what we've done is to bring them together and pool them and to do this other feature as a separate matter in trying to create additional liquidity. It is -- the allocation problem is a difficult problem,

and in fact, we're trying to confront it directly by this cataloging process.

MR. THILLY: If I could comment, I think you're exactly right in what you said, that there probably is an overallocation problem which will have to be dealt with. And my 107 may have to be brought down to 100. My issue on allocation is that it's not done on a load ratio basis where I get 30, which is significantly different, since I've contracted for 30 years for 107.

MR. SMITH: Steve, just to clarify your comments, when you pool all those existing agreements and take into account diversity and other things, what's the difference between that pooling and defining obligations?

MR. WALTON: What do you mean "defining obligations"?

MR. SMITH: As I understood your initial allocation process was going to define those rights as options rather than obligations.

MR. WALTON: That's correct.

MR. SMITH: Okay. I'm trying to understand, when you pool these agreements together, how is that not considering obligations associated with those existing agreements?

MR. WALTON: The party who -- let me give you an example. If Bonneville had some conflicts in the past,

in order to dissolve those they had to redispach. When they put the catalog rights in there, they also have to commit to provide the resource or asset or pay it money to make that whole. In other words, in order to honor their original agreement with the customer, they had to do some redispach or they had to pay someone else. Then they continued to have to do that, and that's a part of this cataloging process.

But the catalog -- are you saying having catalogued them, will we release more or less as options or obligations? We've been around that a couple of times here, but I don't think that's the question you were asking me.

MR. SMITH: No. If a participant has to take on an obligation to create a counterflow, then what's the difference in that and issuing obligations?

MR. WALTON: Okay. They have -- to the extent that they have in the past, the thing is that they're not obligated in all hours. In the past their obligations may have only occurred across the 10 hours of a peak or in an unusual circumstance when there was extremely cold weather or some other circumstances. So they were rather limited in the past, and they had always taken a look at the total set and said gee, can I honor this? Well, it will cost me a little bit in a couple hours, but I will manage that.

To turn all those into obligations and obligate them in all hours is a problem. So we've attempted to use the catalog as a way to say okay, let's corner the existing rights, let's corner this other process so that we can release and provide as much liquidity as we can to the outside market so that we can get as much out.

So when the RTO takes that entire catalog and it's making a decision on whether to release the options or obligations, as you will, then it will have that consolidated set of materials to work from rather than a whole set of -- the problem with the grandfathering necessarily in other formats is if you simply pull the capacity off the table, then you create this phantom congestion problem, and we didn't want to do that.

MS. FERNANDEZ: Why don't we see if --

MR. ROTGER: Thank you. Jose Rotger, R-o-t-g-e-r. We spent about an hour and a half or two hours now talking about fairness issues, allocation of the legacy system, and I don't want to minimize the importance of that. But I want to ask this question that is much closer to my heart, which is I'd like to ask the panel how or more precisely do you see transmission rights as presently structured as sufficient to encourage new transmission investment? Is there a preference between physical or financial for new transmission investment for

encouraging for financing, for building new transmission?

Again, putting aside the issue of who gets what they paid for historically, because that's a thorny issue, and the Commission is in a very difficult position there, and it's ultimately going to have to decide these issues based on a fairness and equity judgment. But moving forward to new investment, if I could ask the panel to comment on the ability of transmission rights to finance that investment, whether physical or financial.

MR. SMITH: I guess I can start. We heard from one of the panelists earlier who is in the business of building new transmission that, in fact, financial rights are adequate to provide the incentives necessary to construct new transmission. One of the issues that we didn't really discuss and I'm sort of curious to raise response to that, but it would seem to me that in the case of -- especially in the case of a DC-type project, when there may be benefits associated with capacity or other ancillary services, including regulation and operating reserves, whether or not a purely financial property right actually secures those benefits to the subscribers or not. My view is that there could be instances, one in the case of a DC-type facility, where a physical rights definition may be easier to make sure that the beneficiaries do actually receive those benefits and being able to provide

some nonstandard products.

MR. COXE: The answer would be yes, you can market structures in which physical rights for particular types of transmission projects provide greater value, but I think if you were to just continue the hard slog through financial property rights of all types a bit further, you could probably reveal financial rights associated not only with the transmission of energy or capacity, but also ancillary services or the ancillary services that the DC facility can provide directly.

And I think you can construct an analog to an FTR that represents differential prices for operating reserves, for example. That's a bit further out, and I don't think that's necessarily a day 1 or even day 2 issue, but it's one that's out there and is a mechanism that any transmission investment -- I wouldn't confine it to a DC facility, because other transmission-type facilities, whether they be an SVC, a fax device, or even an AC transmission line can do other things besides just create FTRs and just deliver installed capacity.

I think that's most of the game, and I think if you get the right market structure in place, as we feel, the type of transmission rights I've discussed earlier, I think that can finance a substantial portion of the transmission. There may be some transmission you can't

finance either because the market fails or because there's some value that the transmission is bringing that isn't captured, but I think that gets you most of the game, and that's a pretty good day 1 objective, I would suggest.

MR. MEAD: As you continue to answer that question, can the various speakers explain what you mean by a physical right and how it would differ from a financial right?

MR. WALTON: It seems to me the physical right's chief attribute is that it has a blocking capability. If you don't own it, you can't schedule. That's a physical right. Once anybody can schedule, then it's different flavors of financials to me. And the only place -- the place I can see an application for a physical right perhaps initially is at the boundaries between two parties, and the reason is because the two separate systems will be generating prices independently to some degree, and so there will be a price discontinuity.

So the party doing a transaction across the boundary may need to secure the -- guarantee the flow or the schedule -- pardon the archaic term -- the schedule in order to hold its price across that boundary. That's probably an expedient until we figure out a way to make this discontinuity between systems go away so that the prices align at the boundaries and we don't have that.

MS. FERNANDEZ: Unless someone else --

MR. THILLY: Can I make one statement? I think the structure of ownership of transmission is more important than the sale of transmission of rights in terms of getting investment. Since we've had divestiture in Wisconsin to a stand-alone transmission company, the budget has gone up tremendously from when it was the individual vertically owned companies.

MR. ROVEN: Carl Roven from SVP. Have you had any thoughts on how you'll deal with the traditional loop flows and how those are handled -- how the rights for those are handled?

MR. WALTON: At least in the weather SCC, we anticipate initially that the -- well, I can't remember what the term stands for, this agreement that allows us to use the phase shifters to minimize loop flow but to stay in place. To the extent that the loop flows are creating some congestion in addition to that, I think initially that would be done there. If we can figure out a way to do what I just talked about where when the prices across the discontinuity are tied together, the issue of loop flow goes away because in an LMP system, there is no such thing.

MR. NAUMANN: That's why it's so important to have the same market design for all the RTOs, so that

those -- because transactions are subject to loop flow between RTOs, and if, for example, you had financial rights in two RTOs, the physical rights in one RTO which implied you needed the right to schedule and you didn't have exactly the right, you could really mess things up. So the basic thing is to have the same -- again, most of the people, I think, were fairly unanimous on financial rights, but it needs to be the same market design. Otherwise, you do run into problems due to loop flows.

MR. MEAD: Can I just follow up? I don't fully understand that, just because my understanding is, you know, if we have multiple RTOs, say, on this eastern interconnect, and each RTO had the same LMP type market design, it would presumably still consider only the transmission constraints within its control area in deciding whether there are -- you know, what the LMP prices were going to be.

And so let's say in the Midwest ISO -- or in PJM, there's no congestion for a moment. So all the LMP prices were the same. But some of its transactions involved some loop flow that congested New York. I presume PJM would not consider that congestion, and even if they had identical market designs, the fact that you have different control areas would mean that the loop flow would go unpriced. Is that wrong?

MS. MANZ: Loop flow is essentially uncompensated use of the system. And if I understand the point, once you go to a network market that's across the entire network, part a standard market design, the notion of this uncompensated flow would go away, because it would be priced in somebody's market. And I think that's -- is that what you're saying, Steve?

MR. NAUMANN: Absolutely.

MR. WALTON: But you're going to have price discontinuities at the junction.

MS. MANZ: Only if they're totally disconnected. That was my point of making sure you share the information across the seams so you don't have the discontinuity.

MR. WALTON: Which implies trading prices back and forth to settle that, and at least on day 1, I don't think that's going to happen.

MS. MANZ: Right. I think your point is a good one. You have to have something up and running before you can coordinate it with something else. I don't think one necessarily follows far behind the other. And I believe that's why we're seeing sort of these joint efforts between PJM and the Midwest ISO, and in fact, you will have this coordination effort effective March 1st when Allegheny becomes a part of PJM West. You will indeed

have the first example of coordinating a market across two different control areas. So pretty soon we're going to see how this works.

MS. FERNANDEZ: Do we have any other brief questions?

MR. TULLMAN: I have one. I'm Bob Tullman with LG&E Energy. This morning's group and this afternoon's group with regard to transmission expansion, it came up that high LMP wasn't a good vehicle to incent that because those seeking to capture the premium, once they built a facility, whether it's local generation or lines or substation upgrades, what have you, the premium goes away.

I guess my question to the panel is, what about those paying the premium? Aren't they incented to finance the upgrade? If you could comment on that.

MR. WALTON: Exactly.

MR. SCHNITZER: Yes.

MS. MANZ: I think that was the point made earlier, that somebody called it selling forward. That is indeed what you're selling forward, the congestion relief. Even though you no longer have the price differences in your profit stream or your revenue stream, you will have the fact that you sold forward the congestion relief. So yes, you're absolutely correct.

MS. FERNANDEZ: With that noted unanimity, that

seems like a good point to end. I would like to thank the panel for a very informative discussion.

Tomorrow, we're going to start at 10:00 tomorrow morning, same place, and the first morning's panel will be on generation adequacy. Thank you.

(Whereupon, at 4:50 p.m., the conference was adjourned, to be reconvened at 10:00 a.m., on Wednesday, February 6, 2002.)